Seneca Nation of Indians

President - Matthew B. Pagels
Clerk - Marta L. Kettle

12837 ROUTE 438
CATTARAUGUS TERRITORY
SENECA NATION
IRVING, NY 14081

Tel. (716) 532-4900
FAX (716) 532-6272

Treasurer - Rickey L. Armstrong Sr.

90 OHI:YO' WAY
ALLEGANY TERRITORY
SENECA NATION
SALAMANCA, NY 14779

Tel. (716) 945-1790
FAX (716) 945-1565

PRESIDENT'S OFFICE

August 31, 2021

Kevin Rowsey, Senior Permit Specialist
U.S. Environmental Protection Agency
Source Water & UIC Section, Region III
1650 Arch Street
Philadelphia, PA 19103
EMAIL: Rowsey.kevin@epa.gov

RE: Government-to-Government Consultation/Coordination and Comments on Proposed UIC Permit Issuance to Sandstone Development, LLC; PAS2R420BMCK

Dear Mr. Rowsey:

The Seneca Nation is in receipt of Acting Regional Administrator Diana Esher's letter dated May 7, 2021, which offers the Nation the opportunity to comment on the draft permit PAS2R420BMCK for a Class II-R enhanced recovery injection well and to consult and coordinate with Region III on this matter. **Please take notice that the Seneca Nation declines the consultation offer at this time. However, the Seneca Nation is submitting written comments regarding proposed permit PAS2R420BMCK (please see attached comments).**

Thank you for sharing information with the Seneca Nation regarding proposed permit PAS2R420BMCK and we look forward to your careful consideration of our comments.

Sincerely,

Matthew B. Pagels
Seneca Nation President

Enclosures

Electronic cc: Brian Hamilton, U.S. EPA Region III
Grant Jonathan, U.S. EPA Region II

Seneca Nation Comments for the Proposed Underground Injection Well
API Number 37-083-53736
Sandstone Development, LLC
Bradford Township, McKean County, Pennsylvania

Operator: Sandstone Development LLC, 557 Interstate Parkway, Bradford, PA 16701
Well name: Moody Lot 5 #17
Location: Bradford, McKean County, 41 54 34.3800, - 78 35 15.7000, East Branch of Tunungwant Creek watershed, in the headwaters of Kendall Creek and Minard Run
Conventional well permit #: API # 37-083-53736
Original permit issue date: 8/13/2008
Well drilling complete: 5/8/2009
Producing Dates: 3/1/2009 - 12/1/2020
Well status: active
UIC permit #: PAS2R420BMCK

1. *The permit should not be granted.* Sandstone Development LLC submitted a US EPA permit on 3/15/2021 to convert a conventional well to a Class II-R (enhanced recovery) Underground Injection Control (UIC) well. Federal UIC Class II statutory mandates fail to address the hazards associated with the oil and gas industry operation while also lacking oversight with self-reporting. There is no measurable assurance water resources are protected.

2. Cumulative impacts of oil and gas related activities in the Upper Allegheny basin have an effect on the Allegheny River and Seneca Nation territory, yet the capacity of the Upper Allegheny watershed to handle existing and proposed oil and gas development has never been assessed.

3. The permit does not address or even mention long-term cumulative impacts. This is of particular concern since the EPA has already permitted 39 Class II ICU wells in the Allegheny River Basin, more than in any other basin in the state, plus there are many unconventional wells and numbers are increasing (the last 9 drilling permits granted by PA were in Elk County).

4. UIC well construction in PA is precedent setting. From a 1/14/21 Pittsburgh Post-Gazette article: "There are approximately 180,000 Class II wells in the U.S., 20%, or 36,000 used for disposal of oil and gas drilling and fracking wastewater. The EPA estimates that more than 2 billion gallons of those fluids are injected into such wells in the U.S. each day, mostly in Texas, California, Oklahoma, and Kansas." The article also mentioned that there were only 13

injection wells in PA, 8 of which are operating. However, there are 42 permitted IUC Class 2R wells listed on the EPA's web site. Of these, 39 are located in the Allegheny River Basin, 2 in the Susquehanna River Basin but still very close to the headwaters of the Allegheny River, one in a tributary of the Ohio River. Some may be inactive, but the fact that they are almost all located in the Allegheny watershed is a concern since groundwater plays a big part in the high quality of the Allegheny River.

5. The proposed UIC well could affect the headwaters of 2 unnamed headwater tributaries of the East Branch of Tunungwant Creek and waterways downstream (Kendall Creek, Minard Run, Tunungwant Creek, and the Allegheny River). Failures and even normal operations could increase the risk of toxic chemical and radioactive contamination of surface and groundwater. While groundwater contamination is the primary concern, there are also related risks to surface water (explosions, spills related to transport and storage, etc.). Even one spill or failure could have severe consequences. There is no way to clean up contaminated groundwater other than natural attenuation and attenuation of radioisotope contamination would take more than 1000 years.

6. Bromide increases toxicity that is detrimental to aquatic life, particularly mussels. The Allegheny River is home to three federally listed endangered mussels. Seneca Nation waterways are home to the Clubshell, Riffleshell and Rayed Bean mussels. Therefor as part of this permit, it is necessary to include Bromide in monitoring.

7. Injection pressure increases seismicity. The permit application includes a general PADCNR report on seismicity but no site-specific discussion. Injection well pressure caused earthquakes in to Youngstown, OH, even though, similar to Potter County; the level of earthquake hazard is low there.

8. Information included in the permit application is very limited. The maps show more than 100 conventional wells in Sandstone's Moody but there is no discussion regarding numbers in the Andrus McDowell field or well types (conventional or unconventional). A short contingency plan was provided but seems insufficient given the amount of wastewater that will be injected (Avg 40 barrels /day, Max 100 barrels / day) and also stored on site (500 barrels or 12,500 gallons of wastewater plus biocides and other injection additives).

9. Require an assessment of well integrity on the surrounding wells; well #17 was only well that had injectivity test conducted. Structural deficiencies in any nearby well will increase risks. Regulations address UIC construction, operation, monitoring & testing, reporting and closure requirements. However, no discussion regarding Sandstone's compliance record is available.

10. Site geology discussion is missing from the permit application; only item provided is the 2009 driller's logs for the wells located in ¼-mile radius of well #17. An assessment of the geology is vital to prevent contamination of drinking water sources.

11. Very limited information was included in the permit application regarding the quality of the wastewater that will be accepted other than a lab report for one sample of unknown origin which may or may not be representative of wastewater that will be accepted, and only a few wastewater related parameters were analyzed.

12. The permit only requires that the wastewater be samples initially then once every 2 years for a few pertinent parameters but not all major wastewater contaminants of concern. Monitoring should be required monthly for the first year of operation.

13. The permit does not require analyses for many contaminants of concern: radionuclides, heavy metals (Al, As, Be, Cd, Co, Cu, Pb, Li, Mo, Zn, Strontium, thallium, selenium, etc.), diesel fuel and other petroleum hydrocarbons, nutrients (TP, NH3, NO3/NO2), or VOC's (BTEX) and other organic compounds. Therefore, even if Sandstone complies with the permit, it is impossible to characterize wastewater.

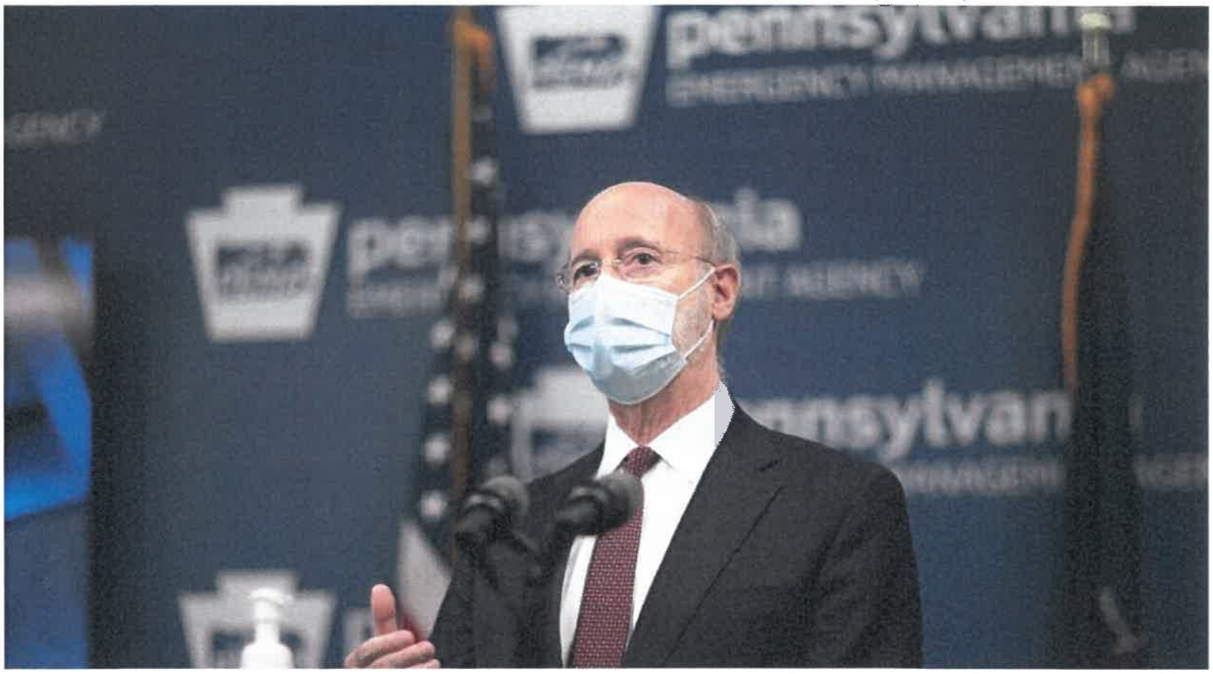
14. Additional pollutants of concern are Calcium, Phosphates, Nitrates, Potassium, Sulfates, Bromide and Strontium. Minimally, more analytes should be added to the monitoring requirements (i.e. 2,4,6-Trichlorophenol, 2-Butanone, acetone, acetophenone, benzene, ethyl benzene, glycol, methyl alcohol, o-Cresol, p-Cresol, phenolics, pyridine, surfactants, pH, turbidity, and conductivity) with increased frequency of testing for contaminants of concern (i.e. Cadmium, Chromium, Copper, and Radium).

15. Failures and even normal operations increase the risk of toxic chemical and radioactive contamination of surface and groundwater. While groundwater contamination is the primary concern, there are also related risks to surface water (explosions, spills related to transport and storage, etc.).

16. Enhanced oil recovery wells extract additional oil and natural gas resources that primary recovery was unable to produce. This is needless. Additionally, injection of fluids or gases into the reservoir moves or "pushes" the oil or natural gas to surrounding producing wells, making the resource available for production so it is necessary to determine the possible influence of the surrounding wells on the proposed injection well (pressures, failures, and groundwater contamination, etc.).

17. The US EPA should require identification of all affected special status species due to habitat loss and fragmentation caused by disruption from noise and traffic at the proposed injection well site. Likewise, the US EPA should require Sandstone to comply with the US EPA and USFWS guidelines for mitigating or reducing impacts on special status species. All plans should seek to reduce the risk of habitat loss and species. Special buffers or protections necessary for historic or cultural resources should be determined based on individual site conditions. The current application lacks sufficient information to make these determinations with respect to special status species.

18. Increased inspection frequency minimizes impact due to well integrity failures. Operators are required to do so-called "mechanical integrity" tests at regular intervals, at least once every five years for Class II wells. This interval is too long. Although, repair of most well failures occurs within six months of discovery, as US EPA data shows, with as much as five years passing between integrity tests, irreversible contamination may happen. Of 6,466 well drilled in Pennsylvania, USA between 2008 to 2013 3.4% had well integrity and barrier issues with 0.24% causing leak to surface (Vidic et al., 2013).



Governor asked to intervene on Plum wastewater injection well

DON HOPEY
Pittsburgh Post-Gazette
dhopey@post-gazette.com

JAN 14, 2021 | 10:47 AM

Community and environmental organizations have asked Gov. Tom Wolf to revoke a state issued permit for a shale gas fracking waste disposal well in Plum, saying the well could endanger public drinking water supplies in Pittsburgh and nearby communities.

Protect PT, the Breathe Collaborative, and Citizens for Plum say in the letter to the governor that allowing the Penneco Sedat #3A class 2 waste injection well to operate will significantly increase the risk of toxic chemical and radioactive contamination of surface and groundwater, cause mine subsidence and increase chances of earthquakes.

The letter, dated Wednesday, Jan. 13, and co-signed by 45 additional organizations and individuals, calls on the governor to nullify the state permit to protect the Allegheny River as a source of drinking water for the city of Pittsburgh and other communities.

"With this urgent action," the letter states, "you will protect our families, our communities and most importantly our water from the troubling, secretive, radioactive and toxic waste of the gas industry."

"It's short-sighted to issue a permit and allow this well to operate given its long-term potential impact on city of Pittsburgh drinking water," Gillian Graber, executive director of Protect PT, said in a virtual news conference Thursday.

Delmont-based Penneco Environmental Solutions received a permit from the state Department of Environmental Protection in April 2020 that allows it to convert the former oil and gas well into a 1,900-foot deep wastewater disposal well that can accept more than 2.27 million gallons of briny, chemically contaminated fracking wastewater a month. The facility, which would be the first deep disposal well in Allegheny County, received a federal Environmental Protection Agency permit in March 2018.

Opponents of the well, many of whom testified in opposition to the facility at public hearings, say in the letter to the governor that revocation of the state permit is warranted because of recently discovered structural deficiencies in the well, the potential for mine subsidence and earthquakes, and the disposal of radioactive wastewater that can cause cancer.

Anthony Ingraffea, a professor of engineering at Cornell University, said Penneco and the DEP used old and inferior testing methods to determine if the well, which was drilled in 1989 into the Murrysville sandstone formation but never put into production, is structurally sound.

"The injection would occur only about 1,000 ft. below the groundwater aquifer, which means there is a high probability of upward migration of fracking waste through defects in the well's 30-year old casing," Mr. Ingraffea stated in the release. "And that presents a serious risk to well and surface water."

He said at the news conference that the high, repeated pressures used to force the wastewater down the well makes the well "inadequate to its new purpose."

The news release also states that Plum Borough is extensively undermined and the well was originally drilled through the Renton Coal Mine, a portion of which has been on fire since 1959, causing unknown structural degradation.

Ben Wallace, Penneco chief operating officer, said all of the issues raised in the letter have been raised in state and federal public hearings on the permits and settled to the satisfaction of the regulatory agencies.

"The regulatory agencies have investigated fully in terms of protecting the public and the risk is not there," said Mr. Wallace, who disputed characterizations that there are inadequacies or deficiencies in the company's permits or operations.

Marc Jacobs, Penneco senior vice president, said the company plans to begin accepting waste at the Plum facility in March. He said the company will closely monitor radioactivity levels at the well, and noted that a deep injection well it operates in West Virginia produces "extremely low" radioactivity readings.

In response to questions the governor's office will review the letter, but it said the governor does not have the authority to revoke or suspend permits. It said also that ensuring that permitted projects meet all statutory and regulatory requirements is the responsibility of DEP and the department will review the details of the Plum well.

The DEP issued a statement saying many of the concerns raised by opponents Thursday were addressed in the comment and response document issued by the department in conjunction with its decision on the permit.

That decision document states, "Penneco's proposed operation is sufficient to protect surface water and water supplies, and it is improbable that disposal into the proposed Sedat #3A well would be prejudicial to the public interest. In consideration of the proposed well's mechanical protections and the injection zone's distance and geologic separation from public natural resources, the Department believes public natural resources will be conserved and maintained."

Matt Kelso, a Plum resident and manager of data and technology at Fractracker Alliance, an environmental nonprofit that tracks and maps shale gas development, said wastewater injection wells can put pressure on geologic fault lines, producing earthquakes.

"The company says that won't happen because this is shallower well, far away from basement rock, but there's evidence these types of wells have also caused seismic activity in sedimentary rock layers," Mr. Kelso said.

The Penneco deep injection well, classified by the EPA as a Class II well, is one of 13 permitted for disposal of oil and gas drilling and fracking wastewater in the state, according to the DEP. Eight are currently operating.

There are approximately 180,000 Class II wells in the U.S., 20%, or 36,000 used for disposal of oil and gas drilling and fracking wastewater. The EPA estimates that more than 2 billion gallons of those fluids are injected into such wells in the U.S. each day, mostly in Texas, California, Oklahoma, and Kansas.

The letter to the governor requests "an immediate and comprehensive investigation" of fracking waste, including impacts of naturally occurring radioactive materials and brine brought to the surface during deep drilling and fracking in the Marcellus and Utica shales. It states that studies are needed to determine if there is a link between the radioactive waste from shale gas drilling and fracking operations and liver, breast and bone cancer.

"Studies (like the one currently underway at University of Pittsburgh) are needed to examine the potential link between the radium in fracking waste and the spike of rare childhood cancers, including Ewing sarcoma, in Pennsylvania's Marcellus Shale," the groups wrote in the governor's letter.

"Fracking has a toxic and radioactive waste problem that has never been adequately addressed and solved," said Dr. Ned Ketyer, a consultant with the Southwestern Pennsylvania Environmental Health Project. "Injecting this waste into an unstable well in close proximity to our region's drinking water source is a shortsighted and irresponsible plan, and will make people sick. It should be abandoned immediately."

Don Hopey: dhopey@post-gazette.com or 412-263-1983

First Published January 14, 2021, 10:47am

Impact of Shale Gas Development on Regional Water Quality

R. D. Vidic,[1*] S. L. Brantley,[2] J. M. Vandenbossche,[1] D. Yoxtheimer,[2] J. D. Abad[1]

Background: Natural gas has recently emerged as a relatively clean energy source that offers the opportunity for a number of regions around the world to reduce their reliance on energy imports. It can also serve as a transition fuel that will allow for the shift from coal to renewable energy resources while helping to reduce the emissions of CO_2, criteria pollutants, and mercury by the power sector. Horizontal drilling and hydraulic fracturing make the extraction of tightly bound natural gas from shale formations economically feasible. These technologies are not free from environmental risks, however, especially those related to regional water quality, such as gas migration, contaminant transport through induced and natural fractures, wastewater discharge, and accidental spills. The focus of this Review is on the current understanding of these environmental issues.

Advances: The most common problem with well construction is a faulty seal that is emplaced to prevent gas migration into shallow groundwater. The incidence rate of seal problems in unconventional gas wells is relatively low (1 to 3%), but there is a substantial controversy whether the methane detected in private groundwater wells in the area where drilling for unconventional gas is ongoing was caused by well drilling or natural processes. It is difficult to resolve this issue because many areas have long had sources of methane unrelated to hydraulic fracturing, and pre-drilling baseline data are often unavailable.

Water management for unconventional shale gas extraction is one of the key issues that will dominate environmental debate surrounding the gas industry. Reuse of produced water for hydraulic fracturing is currently addressing the concerns regarding the vast quantities of contaminants that are brought to the surface. As these well fields mature and the opportunities for wastewater reuse diminish, the need to find alternative management strategies for this wastewater will likely intensify.

Outlook: Improved understanding of the fate and transport of contaminants of concern and increased long-term monitoring and data dissemination will help effectively manage water-quality risks associated with unconventional gas industry today and in the future. Confidentiality requirements dictated by legal investigations combined with the expedited rate of development and the limited funding for research are major impediments to peer-reviewed research into environmental impacts. Now is the time to work on these environmental issues to avoid an adverse environmental legacy similar to that from abandoned coal mine discharges in Pennsylvania.

Drilling multiple horizontal wells from a single well pad allows access to as much as 1 square mile of shale that is located more than a mile below. [Image courtesy of Range Resources Appalachia]

[1]Department of Civil and Environmental Engineering, University of Pittsburgh, Pittsburgh, PA 15261, USA. [2]Earth and Environmental Systems Institute and Department of Geosciences, Pennsylvania State University, University Park, PA 16802, USA.
*Corresponding author. E-mail: vidic@pitt.edu

READ THE FULL ARTICLE ONLINE
http://dx.doi.org/10.1126/science.1235009

Cite this article as R. Vidic *et al.*, *Science* **340**, 1235009 (2013). DOI: 10.1126/science.1235009

ARTICLE OUTLINE

BACKGROUND READING

General overview that includes geology of major shale plays, description of the extraction process, relevant regulations, and environmental considerations: www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf

Detailed information about individual shale gas wells, including chemical additives used in each hydraulic fracturing treatment: http://fracfocus.org

Findings of the U.S. Environmental Protection Agency study on the potential impact of hydraulic fracturing on drinking water resources: www.epa.gov/hfstudy

Comprehensive information from the British Geological Survey about shale gas (including articles and videos): www.bgs.ac.uk/shalegas

Site developed in collaboration with the Geological Society of America promoting the rational debate about energy future: www.switchenergyproject.com

Latest news and findings about shale gas. www.shale-gas-information-platform.org

Impact of Shale Gas Development on Regional Water Quality

R. D. Vidic,[1]* S. L. Brantley,[2] J. M. Vandenbossche,[1] D. Yoxtheimer,[2] J. D. Abad[1]

Unconventional natural gas resources offer an opportunity to access a relatively clean fossil fuel that could potentially lead to energy independence for some countries. Horizontal drilling and hydraulic fracturing make the extraction of tightly bound natural gas from shale formations economically feasible. These technologies are not free from environmental risks, however, especially those related to regional water quality, such as gas migration, contaminant transport through induced and natural fractures, wastewater discharge, and accidental spills. We review the current understanding of environmental issues associated with unconventional gas extraction. Improved understanding of the fate and transport of contaminants of concern and increased long-term monitoring and data dissemination will help manage these water-quality risks today and in the future.

Natural gas has recently emerged as an energy source that offers the opportunity for a number of regions around the world to reduce their reliance on energy imports or strive toward energy independence (*1*, *2*). It may also be a potential transition fuel that will allow for the shift from coal to renewable energy resources while helping to reduce the emissions of CO_2, criteria pollutants, and mercury by the power sector (*3*). The driving force behind this shift is that it has become economically feasible to extract unconventional sources of gas that were previously considered inaccessible. Conventional gas is typically extracted from porous sandstone and carbonate formations, where it has generally been trapped under impermeable caprocks after migration from its original source rock. In contrast, unconventional gas is usually recovered from low-permeability reservoirs or the source rocks themselves, including coal seams, tight sand formations, and fine-grained, organic-rich shales. Unconventional gas formations are characterized by low permeabilities that limit the recovery of the gas and require additional techniques to achieve economical flow rates (*2*).

The archetypical example of rapidly increasing shale gas development is the Marcellus Shale in the eastern United States (Fig. 1). Intensive gas extraction began there in 2005, and it is one of the top five unconventional gas reservoirs in the United States. With a regional extent of 95,000 square miles, the Marcellus is one of the world's largest known shale-gas deposits. It extends from upstate New York, as far south as Virginia, and as far west as Ohio, underlying 70% of the state of Pennsylvania and much of West Virginia. The formation consists of black and dark gray shales, siltstones, and limestones (*4*). On the basis of a geological study of natural fractures in the formation, Engelder (*5*) estimated a 50% probability that the Marcellus will ultimately yield 489 trillion cubic feet of natural gas.

[1]Department of Civil and Environmental Engineering, University of Pittsburgh, Pittsburgh, PA 15261, USA. [2]Earth and Environmental Systems Institute and Department of Geosciences, Pennsylvania State University, University Park, PA 16802, USA.

*Corresponding author. E-mail: vidic@pitt.edu

Concerns that have been voiced (*6*) in connection with hydraulic fracturing and the development of unconventional gas resources in the United States include land and habitat fragmentation as well as impacts to air quality, water quantity and quality, and socioeconomic issues (*3*, *5*, *7*). Although shale gas development is increasing across several regions of the United States and the world (such as the United Kingdom, Poland, Ukraine, Australia, and Brazil), this review focuses on the potential issues surrounding water quality in the Appalachian region and specifically the Marcellus Shale, where the majority of published studies have been conducted. Our Review focuses on chemical aspects of water quality rather than issues surrounding enhanced sediment inputs into waterways, which have been discussed elsewhere (*4*, *7*, *8*).

Cause of the Shale Gas Development Surge

Recent technological developments in horizontal drilling and hydraulic fracturing have enabled enhanced recovery of unconventional gas in the United States, increasing the contribution of shale gas to total gas production from negligible levels in 1990 to 30% in 2011 (*1*). Although the first true horizontal oil well was drilled in 1929, this technique only became a standard industry practice in the 1980s (*9*). Whereas a vertical well allows access to tens or hundreds of meters across a flat-lying formation, a horizontal well can be drilled to conform to the formation and can therefore extract gas from thousands of meters of shale. Horizontal wells reduce surface disturbance by limiting the number of drilling pads and by enabling gas extraction from areas where vertical wells are not feasible. However, horizontal drilling alone would not have enabled exploitation of the unconventional gas resources because the reservoir permeability is not sufficient to achieve economical gas production by natural flow. Hydraulic fracturing—"hydrofracking," or "fracking"—was developed in the 1940s to fracture and increase permeability of target formations and has since been improved to match the characteristics of specific types of reservoirs, including shales.

Hydraulic fracturing fluids consist of water that is mixed with proppants and chemicals before injection into the well under high pressure (480 to 850 bar) in order to open the existing fractures or initiate new fractures. The proppant (commonly sand) represents generally ~9% of the total weight of the fracturing fluid (*10*) and is required to keep the fractures open once the pumping has stopped. The number, type, and concentration of chemicals added are governed by the geological characteristics of each site and the chemical characteristics of the water used. The fracturing fluid typically used in the Marcellus Shale is called slickwater, which means that it does not contain viscosity modifiers that are often added to hydrofracture other shales so as to facilitate better proppant transport and placement.

Chemical additives in the fluids used for hydraulic fracturing in the Marcellus Shale include friction reducers, scale inhibitors, and biocides (Table 1 and Box 1). Eight U.S. states currently require that all chemicals that are not considered proprietary must be published online (*11*), whereas many companies are voluntarily disclosing this information in other states. However, many of the chemicals added for fracturing are not currently regulated by the U.S. Safe Drinking Water Act, raising public concerns about water supply contamination. From 2005 to 2009, about 750 chemicals and other components were used in hydraulic fracturing, ranging from harmless components, including coffee grounds or walnut hulls, to 29 components that may be hazardous if introduced into the water supply (*6*). An inorganic acid such as hydrochloric acid is often used to clean the wellbore area after perforation and to dissolve soluble minerals in the surrounding formation. Organic polymers or petroleum distillates are added to reduce friction between the fluid and the wellbore, lowering the pumping costs. Antiscalants are added to the fracturing fluid so as to limit the precipitation of salts and metals in the formation and inside the well. Besides scaling, bacterial growth is a major concern for the productivity of a gas well (quantity and quality of produced gas). Glutaraldehyde is the most common antibacterial agent added, but other disinfectants [such as 2,2-dibromo-3-nitrilopropionamide (DBNPA) or chlorine dioxide] are often considered. Surfactants (alcohols such as methanol or isopropanol) may also be added to reduce the fluid surface tension to aid fluid recovery.

Methane Migration

As inventoried in 2000, more than 40 million U.S. citizens drink water from private wells (*12*). In some areas, methane—the main component of natural gas—seeps into these private wells from either natural or anthropogenic sources. Given its low solubility (26 mg/L at 1 atm, 20°C), methane that enters wells as a solute is not considered a health hazard with respect to ingestion and is therefore not regulated in the United States. When present, however, methane can be oxidized by bacteria, resulting in oxygen depletion. Low oxygen concentrations can result in the increased solubility of elements such as arsenic or iron. In addition, anaerobic bacteria that proliferate under such conditions may reduce sulfate to sulfide, creating water- and air-quality issues. When methane degasses, it can also create turbidity and, in extreme cases, explode (*13*, *14*). Therefore, the U.S. Department of the Interior recommends a warning if water contains 10 mg/L of CH_4 and immediate action if concentrations reach 28 mg/L (*15*). Methane concentrations above 10 mg/L indicate that accumulation of gas could result in an explosion (*16*).

The most common problem with well construction is a faulty seal in the annular space around casings that is emplaced to prevent gas leakage from a well into aquifers (*13*). The incidence rate of casing and cement problems in unconventional gas wells in Pennsylvania has been reported previously as ~1 to 2% (*17*). Our count in Pennsylvania from 2008 to March 2013 for well construction problems [such as casing or cementing incidents (*18*)] cited by the Pennsylvania Department of Environmental Protection (DEP) revealed 219 notices of violation out of 6466 wells (3.4%) (*19*). Of these, 16 wells in northern Pennsylvania were given notices with respect to the regulation that the "operator shall prevent gas and other fluids from lower formations from entering fresh groundwater" (violation code 78.73A). Most of the time, gas leakage is minor and can be remedied. However, in one case attributed to Marcellus drilling and leaky well casings, stray gas that accumulated in a private water well exploded near the northeastern Pennsylvania town of Dimock. A study of 60 groundwater wells in that area, including across the border in upstate New York (*20*), showed that both the average and maximum methane concentrations were higher when sampled from wells within 1 km of active Marcellus gas wells as compared with those farther away. Much discussion has since ensued as to whether the methane detected in these wells was caused by drilling or natural processes (*21*–*24*) because the area has long had sources of both thermogenic and biogenic methane unrelated to hydraulic fracturing, and no predrilling baseline data are available. The averages reported in that study for sites both near and far from drilling are not dissimilar from values for groundwater from areas of Pennsylvania and West Virginia sampled by the U.S. Geological Survey (USGS) before the recent Marcellus Shale development began, or samples in New York state where high-volume hydrofracturing is currently banned (Fig. 2).

The reason gas is found so often in water wells in some areas is because methane not only forms at depth naturally, owing to high-temperature maturation of organic matter, but also at shallow depths through bacterial processes (*25*, *26*). Both these thermogenic and biogenic gas types can migrate through faults upward from deep formations or laterally from environments such as swamps (swamp gas) or glacial till (drift gas) (*14*, *27*). In addition, gas can derive from anthropogenic sources such as gas storage fields, coal mines, landfills, gas pipelines, and abandoned gas wells (*28*). In fact, ~350,000 oil and gas wells have been drilled in Pennsylvania, and the locations of ~100,000 of these are unknown (*29*). Thus, it is not surprising that gas problems have occurred in Pennsylvania long before the Marcellus development (*30*). Pennsylvania is not the only state facing this problem because about ~60,000 documented orphaned wells and potentially more than 90,000 undocumented orphaned wells in the United States have not been adequately plugged and could act as vertical conduits for gas (*31*).

As natural gas moves in the subsurface, it can be partially oxidized, mixed with other gases, or diluted along flow paths. To determine its provenance, a "multiple lines of evidence approach" must be pursued (*24*). For example, researchers measure the presence of other hydrocarbons as well as the isotopic signatures of H, O, and C in the water or gas (*16*, *27*, *31*). Thermogenic gas in general has more ethane and a higher $^{13}C/^{12}C$ ratio than that of biogenic gas. Stable isotopes in thermogenic gas may sometimes even yield clues about which shale was the source of the gas (*24*, *32*). In northeastern Pennsylvania, researchers argue whether the isotopic signatures of the methane in drinking-water wells indicate the gas derived from the Marcellus or from shallower formations (*20*, *24*).

Although determining the origin of gas in water wells may lead to solutions for this problem, the source does not affect liability because gas companies are responsible if it can be shown that any gas—not just methane—has moved into a water well because of shale-gas development activity. For example, drilling can open surficial fractures that allow preexisting native gas to leak into water wells (*13*). This means that pre- and post-drilling gas concentration data are needed to determine culpability. Only one published study compares pre- and post-drilling water chemistry in the Marcellus Shale drilling area. In that study, a

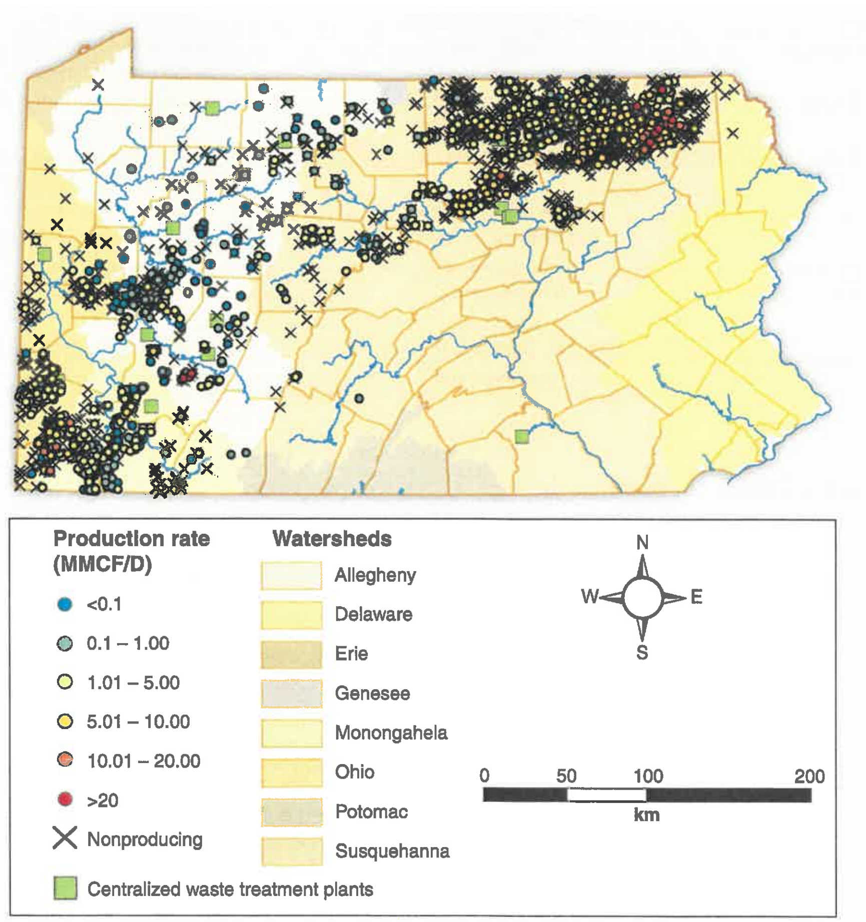


Fig. 1. Marcellus Shale wells in Pennsylvania. Rapid development of Marcellus Shale since 2005 resulted in more than 12,000 well permits, with more than 6000 wells drilled and ~3500 producing gas through December 2012 (average daily production ranged from <0.1 to >20 million cubic feet/day (MMCF/D). Current locations of centralized wastewater treatment facilities (CWTs) are distributed to facilitate treatment and reuse of flowback and produced water for hydraulic fracturing.

sample of 48 water wells in Pennsylvania investigated between 2010 and 2011 within 2500 feet of Marcellus wells showed no statistical differences in dissolved CH_4 concentrations before or shortly after drilling (*33*). In addition, no statistical differences related to distance from drilling were observed. However, that study reported that the concentration of dissolved methane increased in one well after drilling was completed nearby, which is possibly consistent with an average rate of casing problems of ~3%.

The rate of detection of methane in water wells in northeast Pennsylvania [80 to 85% (*20*, *24*)] is higher than in the wider region that includes southwestern Pennsylvania [24% (*33*)], where pre- and post-drilling concentrations were statistically identical. This could be a result of the small sample sizes of the two studies or because the hydrogeological regime in the northeast is more prone to gas migration (*34*). Such geological differences also may explain why regions of the Marcellus Shale have been characterized by controversy in regard to methane migration as noted above, whereas other shale gas areas such as the Fayetteville in Arkansas have not reported major issues with respect to methane (*35*). Reliable models that incorporate geological characteristics are needed to allow prediction of dissolved methane in groundwater. It is also critical to distinguish natural and anthropogenic causes of migration, geological factors that exacerbate such migration, and the likelihood of ancillary problems of water quality related to the depletion of oxygen. Answering some of these questions will require tracking temporal variations in gas and isotopic concentrations in groundwater wells near and far from drilling by using multiple lines of evidence (*16*, *24*). Research should also focus on determining flow paths in areas where high sampling density can be attained.

Table 1. Common chemical additives for hydraulic fracturing.

Additive type	Example compounds	Purpose
Acid	Hydrochloric acid	Clean out the wellbore, dissolve minerals, and initiate cracks in rock
Friction reducer	Polyacrylamide, petroleum distillate	Minimize friction between the fluid and the pipe
Corrosion inhibitor	Isopropanol, acetaldehyde	Prevent corrosion of pipe by diluted acid
Iron control	Citric acid, thioglycolic acid	Prevent precipitation of metal oxides
Biocide	Glutaraldehyde, 2,2-dibromo-3-nitrilopropionamide (DBNPA)	Bacterial control
Gelling agent	Guar/xanthan gum or hydroxyethyl cellulose	Thicken water to suspend the sand
Crosslinker	Borate salts	Maximize fluid viscosity at high temperatures
Breaker	Ammonium persulfate, magnesium peroxide	Promote breakdown of gel polymers
Oxygen scavenger	Ammonium bisulfite	Remove oxygen from fluid to reduce pipe corrosion
pH adjustment	Potassium or sodium hydroxide or carbonate	Maintain effectiveness of other compounds (such as crosslinker)
Proppant	Silica quartz sand	Keep fractures open
Scale inhibitor	Ethylene glycol	Reduce deposition on pipes
Surfactant	Ethanol, isopropyl alcohol, 2-butoxyethanol	Decrease surface tension to allow water recovery

Box 1. Glossary of Terms

Casing: steel pipe that is inserted into a recently drilled section of a borehole to stabilize the hole, prevent contamination of groundwater, and isolate different subsurface zones.

Cementing: placing a cement mixture between the casing and a borehole to stabilize the casing and seal off the formation.

Class II disposal wells: underground injection wells for disposal of fluids associated with oil and gas production.

Flowback water: water that returns to the surface after the hydraulic fracturing process is completed and the pressure is released and before the well is placed in production; flowback water return occurs for several weeks.

Produced water: water that returns to the surface with the gas after the well is placed in production; production water return occurs during the life of a well.

Proppant: granular material, such as silica sand, ceramic media, or bauxite, that keeps the fractures open so that gas can flow to the wellbore.

Slickwater fracturing: fracturing with fluid that contains mostly water along with friction reducers, proppants, and other additives; used for predominantly gas-bearing formations at shallower depths.

Source rock: organic-rich sedimentary rocks, such as shale, containing natural gas or oil.

Stray gas: gas contained in the geologic formation outside the wellbore that is accidentally mobilized by drilling and/or hydraulic fracturing.

How Protective Is the "Well Armor"?

The protective armor shielding the freshwater zones and the surrounding environment from the contaminants inside the well consist of several layers of casing (hollow steel pipe) and cement (Fig. 3). When the integrity of the wellbore is compromised, gas migration or stray gas can become an issue (*14*). Gas migration out of a well refers to movement of annular gas either through or around the cement sheath. Stray gas, on the other hand, commonly refers to gas outside of the wellbore. One of the primary causes of gas migration or stray gas is related to the upper portion of the wellbore when it is drilled into a rock formation that contains preexisting high-pressure gas. This high-pressure gas can have deleterious effects on the integrity of the outer cement annulus, such as the creation of microchannels (*36*). Temperature surveys can be performed shortly after the cementing job is completed in order to ensure that cement is present behind the casing. Acoustic logging tools are also available to evaluate the integrity of the cement annulus in conjunction with pressure testing.

It is well known that to effectively stabilize wellbores with cement in areas with zones of overpressurized gas, proper cement design and proper mud removal are essential (*37*, *38*). If the hydrostatic pressure of the cement column is not higher than the gas-bearing formation pressure, gas can invade the cement before it sets. Conversely, if this pressure is too high, then the formation can fracture, and a loss of cement slurry can occur. Even when the density is correct, the gas from the formation can invade the cement as it transitions from a slurry to a hardened state (*39*). The slurry must be designed to minimize this transition time and the loss of fluid from the slurry to the formation. Also, if drilling mud is not properly cleaned from the hole before cementing, mud channels may allow gas migration through the central portion of the annulus or along the cement-formation interface. Even if the well is properly cleaned and the cement is placed properly, shrinkage of the cement during hydration or as a result of drying throughout the life of the well can result in crack development within the annulus (40, 41).

Although the primary mechanisms contributing to gas migration and stray gas are understood, it is difficult to predict the risk at individual sites because of varying geological conditions and drilling practices. To successfully protect fresh water and the surrounding environment from the contaminants inside the well, the site-specific risk factors contributing to gas migration and stray gas must be better understood, and improvements in the diagnostics of cement and casing integrity are needed for both new and existing wells. Finding solutions to these problems will provide environmental agencies the knowledge needed to develop sound regulations related to the distances around gas wells that can be affected. It will also provide operators the ability to prevent gas migration and stray gas in a more efficient and economical manner.

The Source and Fate of Fracturing Fluid

The drilling and hydraulic fracturing of a single horizontal well in the Marcellus Shale may require 2 million to 7 million gallons of water (42). In contrast, only about 1 million gallons are needed for vertical wells because of the smaller formation contact volume. Although the projected water consumption for gas extraction in the Marcellus Shale region is 18.7 million gallons per day in 2013 (39), this constitutes just 0.2% of total annual water withdrawals in Pennsylvania. Water withdrawals in other areas are similarly low, but temporary problems can be experienced at the local level during drought periods (3). Furthermore, water quantity issues are prevalent in the drier shale-gas plays of the southwest and western United States (43). It is likely that water needs will change from these initial projections as the industry continues to improve and implement water reuse. Nevertheless, the understanding of flow variability—especially during drought conditions or in regions with already stressed water supplies—is necessary to develop best management practices for water withdrawal (44). It is also necessary to develop specific policies regarding when and where water withdrawals will be permitted in each region (45).

After hydraulic fracturing, the pressure barriers such as frac plugs are removed, the wellhead valve is opened, and "flowback water" is collected at the wellhead. Once the well begins to produce gas, this water is referred to as "produced water" and is recovered throughout the life of the well. Flowback and produced waters are a mixture of injected fluids and water that was originally present in the target or surrounding formations (formation water) (42, 46–50). The fraction of the volume of injected water that is recovered as flowback water from horizontal wells in Pennsylvania ranges from 9 to 53% (9, 41), with an average of 10%. It has been observed that the recovery can be even lower than 10% if the well is shut-in for a period of time (51). The well is shut-in—or maintained closed between fracturing and gas production—so as to allow the gas to move from the shale matrix into the new fractures. Two of the key unanswered questions is what happens to the fracturing fluid that is not recovered during the flowback period, and whether this fluid could eventually contaminate drinking water aquifers (23, 33, 34, 52–54). The analyses of Marcellus Shale well logs indicate that the low-permeability shale contains very little free water (55, 56), and much of the hydraulic fracturing fluid may imbibe (absorb) into the shale.

Fracturing fluid could migrate along abandoned and improperly plugged oil and gas wells, through an inadequately sealed annulus between the wellbore and casing or through natural or induced fractures outside the target formation. Indeed, out-of-formation fractures have been documented to extend as much as ~460 m above the top of some hydraulically fractured shales (57), but still ~1.6 km or more below freshwater aquifers. Nonetheless, on the basis of the study of 233 drinking-water wells across the shale-gas region of rural Pennsylvania, Boyer *et al.* (33) reported no major influences from gas well drilling or hydrofracturing on nearby water wells. Compared with the pre-drilling data reported in that study, only one well showed changes in water quality (salt concentration). These changes were noticed within days after a well was hydrofractured less than ~460 m away, but none of the analytes exceeded the standards of the U.S. Safe Drinking Water Act, and nearly all the parameters approached pre-drilling concentrations within 10 months.

In the case of methane contamination in groundwater near Dimock, Pennsylvania, contamination

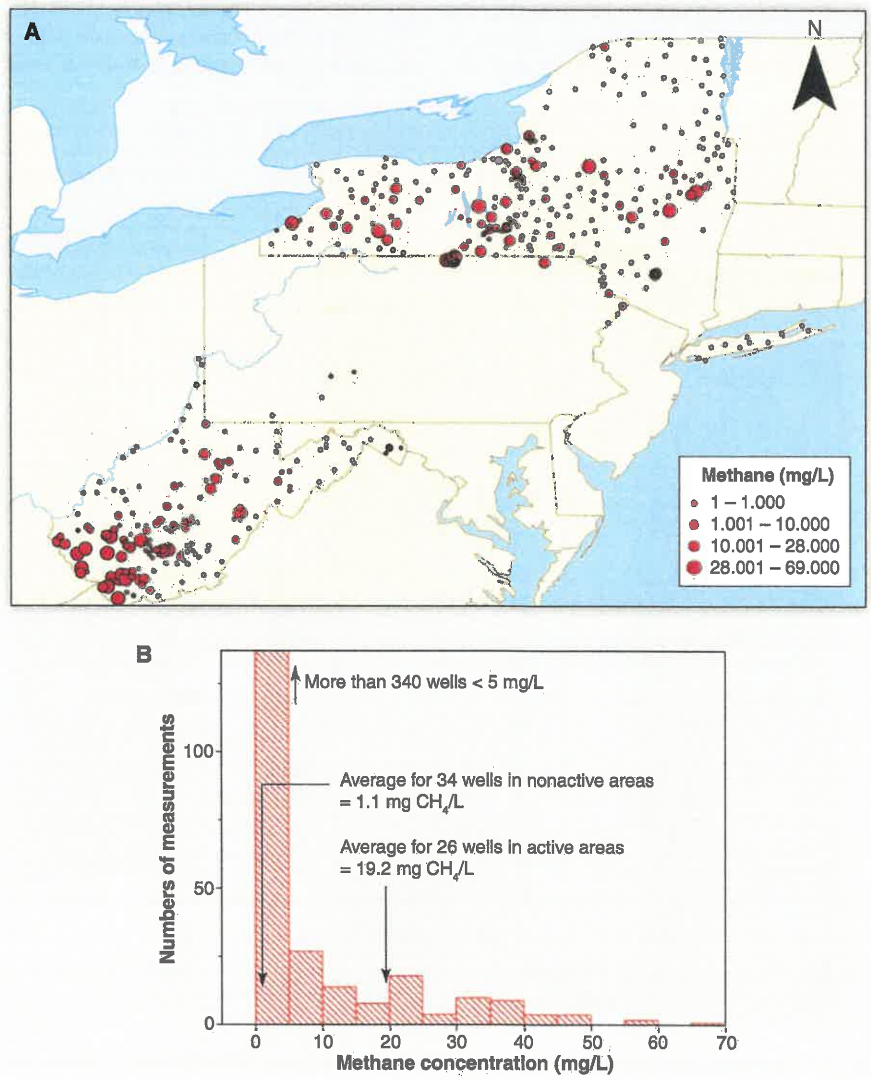


Fig. 2. Methane concentrations in groundwater and springs. (A) Published values for groundwater or spring samples include 239 sites in New York from 1999 to 2011 (84), 40 sites in Pennsylvania in 2005 (27), and 170 sites in West Virginia from 1997 to 2005 (85). Maxima varied from 68.5 mg/L in West Virginia, to 44.8 mg/L in Tioga County, Pennsylvania, where an underground gas storage field was leaking, to a value approaching 45 mg/L in New York. (B) Values shown with down arrows are averages for a set of wells in southeastern New York and northeastern Pennsylvania located <1 km (26 wells) and >1 km (34 wells) from active gas drilling (20).

by saline flowback brines or fracturing fluids was not observed ([20]). One early U.S. Environmental Protection Agency (EPA) report ([54]) suggested that a vertically fractured well in Jackson County, West Virginia, may have contaminated a local water well with gel from fracturing fluid. This vertical well was fractured at a depth of just ~1220 m, and four old natural gas wells nearby may have served as conduits for upward contaminant transport. A recent EPA study ([53]) implicated gas production wells in the contamination of deep groundwater resources near Pavillion, Wyoming. However, resampling of the monitoring wells by the USGS showed that the flowrate was too small to lend confidence to water-quality interpretations of one well, leaving data from only one other well to interpret with respect to contamination, and regulators are still studying the data ([58]). The Pavillion gas field consists of 169 production wells into a sandstone (not shale) formation and is unusual in that fracturing was completed as shallow as 372 m below ground. In addition, surface casings of gas wells are as shallow as 110 m below ground, whereas the domestic and stock wells in the area are screened as deep as 244 m below ground. The risk for direct contaminant transport from gas wells to drinking-water wells increases dramatically with a decrease in vertical distance between the gas well and the aquifer.

A recent study applied a groundwater transport model to estimate the risk of groundwater contamination with hydraulic fracturing fluid by using pressure changes reported for gas wells ([52]). The study concluded that changes induced by hydraulic fracturing could allow advective transport of fracturing fluid to groundwater aquifers in <10 years. The model includes numerous simplifications that compromise its conclusions ([59]). For example, the model is based on the assumption of hydraulic conductivity that reflects water-filled voids in the geological formations, and yet many of the shale and overburden formations are not water-saturated ([60]). Hence, the actual hydraulic conductivity in the field could be orders of magnitude lower than that assumed in the study ([59]). Furthermore, although deep joint sets or fractures exist ([14]), the assumption of preexisting1500-m long vertical fractures is hypothetical and not based on geologic exploration. Hence, there is a need to establish realistic flow models that take into account heterogeneity in formations above the Marcellus Shale and realistic hydraulic conductivities and fracturing conditions.

Last, it has long been known ([14], [34], [47], [48], [61], [62]) that groundwater is salinized where deeper ancient salt formations are present within sedimentary basins, including basins with shale gas. Where these brines are present at relatively shallow depths, such as in much of the northeastern and southwestern United States and Michigan, brines sometimes seep to the surface naturally and are unrelated to hydraulic fracturing. An important research thrust should focus on understanding these natural brine transport pathways to determine whether they could represent potential risk for contamination of aquifers because of hydraulic fracturing.

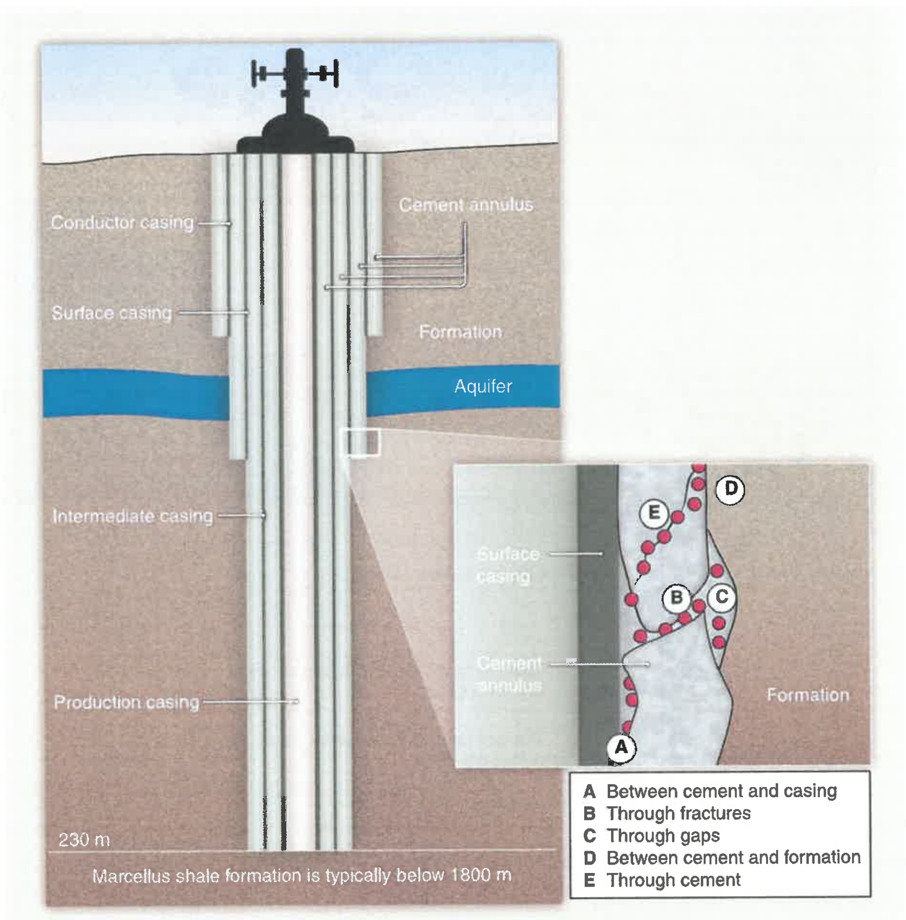


Fig. 3. Typical Marcellus well construction. (i) The conductor casing string forms the outermost barrier closest to the surface to keep the upper portion of the well from collapsing and it typically extends less than 12 m (40 ft) from the surface; (ii) the surface casing and the cement sheath surrounding it that extend to a minimum of 15 m below the lowest freshwater zone is the first layer of defense in protecting aquifers; (iii) the annulus between the intermediate casing and the surface casing is filled with cement or a brine solution; and (iv) the production string extends down to the production zone (900 to 2800 m), and cement is also placed in the annulus between the intermediate and production casing. Potential flaws in the cement annulus (Inset, "A" to "E") represent key pathways for gas migration from upper gas-bearing formations or from the target formation.

Appropriate Wastewater Management Options

The flowback and produced water from the Marcellus Shale is the second saltiest ([63]) and most radiogenic ([50]) of all sedimentary basins in the United States where large volume hydraulic fracturing is used. The average amount of natural gas-related wastewater in Pennsylvania during 2008 to 2011 was 26 million barrels per year (a fourfold increase compared with pre-Marcellus period) ([64]). Compared with conventional shallow wells, Marcellus Shale wells generate one third of the wastewater per unit volume of gas produced ([65]). However, the wastewater associated with Marcellus development in 2010 and 2011 accounted for 68 and 79%, respectfully, of the total oil and gas wastewater requiring management in Pennsylvania. Flowback/produced water is typically impounded at the surface for subsequent disposal, treatment, or reuse. Because of the large water volume, high concentration of dissolved solids, and complex physical-chemical composition of this wastewater, which includes organic and radioactive components, the public is becoming increasingly concerned about management of this water and the potential for human health and environmental impacts associated with the release of untreated or inadequately treated wastewater to the environment ([66]). In addition, spills from surface impoundments ([14]) and trucks or infiltration to groundwater though failed liners are potential pathways for surface and groundwater contamination by this wastewater.

Treatment technologies and management strategies for this wastewater are constrained by regulations, economics of implementation, technology performance, geologic setting, and final disposal alternatives ([67]). The majority of wastewater from oil and gas production in the United States is disposed of effectively by deep underground injection ([68]). However, the state of Pennsylvania has only five operating Class II disposal wells. Although underground injection disposal wells will likely increase in number in Pennsylvania, shale gas development is currently occurring in many areas where Class II disposal wells will not be readily available. Moreover, permissions for and construction of new disposal wells is complex, time-consuming, and costly. Disposal of Pennsylvania brines in Ohio and West Virginia is ongoing but limited by high transportation costs.

The lack of disposal well capacity in Pennsylvania is compounded by rare induced low-magnitude seismic events at disposal wells in other locations (69–71). It is likely that the disposal of wastewater by deep-well injection will not be a sustainable solution across much of Pennsylvania. Nonetheless, between 1982 and 1984, Texas reported at most ~100 cases of confirmed contamination of groundwater from oilfield injection wells, saltwater pits, and abandoned wells, even though at that time the state hosted more than 50,000 injection wells associated with oil and gas (72). Most problems were associated with small, independent operators. The ubiquity of wells and relative lack of problems with respect to brine disposal in Texas is one likely explanation why public pushback against hydraulic fracturing is more limited in Texas as compared with the northeastern United States.

Another reason for public pushback in the northeast may be that in the early stages of Marcellus Shale development, particularly in 2008 to 2009, flowback/produced water was discharged and diluted into publicly owned treatment works (POTWs, or municipal wastewater treatment plants) under permit. This practice was the major pathway for water contamination because these POTWs are not designed to treat total dissolved solids (TDS), and the majority of TDS passed directly into the receiving waterways (6, 73), resulting in increased salt loading in Pennsylvania rivers, especially during low flow (74). In response, the Pennsylvania DEP introduced discharge limits to eliminate disposal of Marcellus Shale wastewater to POTWs (75). In early 2010, there were 17 centralized waste treatment plants (CWTs) in Pennsylvania that were exempted from the TDS discharge limits. However, according to Pennsylvania DEP records none of these CWTs reported to be currently receiving Marcellus wastewater, although they may receive produced water from conventional gas wells. Nevertheless, the TDS load to surface waters from flowback/produced water increased from ~230,000 kg/day in 2006 to 350,000 kg/day in 2011 (64).

It is difficult to determine whether shale gas extraction in the Appalachian region since 2006 has affected water quality regionally, because baseline conditions are often unknown or have already been affected by other activities, such as coal mining. Although high concentrations of Na, Ca, and Cl will be the most likely ions detected if flowback or produced waters leaked into waterways, these salts can also originate from many other sources (76). In contrast, Sr, Ba, and Br are highly specific signatures of flowback and produced waters (34, 47). Ba is of particular interest in Pennsylvania waters in that it can be high in sulfate-poor flowback/produced waters but low in sulfate-containing coal-mine drainage. Likewise, the ratio of $^{87}Sr/^{86}Sr$ may be an isotopic fingerprint of Marcellus Shale waters (34, 77).

Targeting some of these "fingerprint" contaminants, the Pennsylvania DEP began a new monitoring program in 2011. Samples are collected from pristine watersheds as well as from streams near CWT discharges and shale-gas drilling. The Shale Network is collating these measurements with high-quality data from citizen scientists, the USGS, the EPA, and other entities in order to assess potential water quality impacts in the northeast (78, 79). Before 2003, mean concentrations in Pennsylvania surface waters in counties with unconventional shale-gas development were 27 ± 32, 550 ± 620, and 72 ± 81 μg/L for Ba, Sr, and Br ($\pm 1\sigma$), respectively (Fig. 4). Most values more than 3σ above the mean concentrations since 2003 represent samples from areas of known brine effluents from CWTs. A concern has been raised over bromide levels in the Allegheny River watershed that may derive from active CWTs because of health effects associated with disinfection by-products formed as a result of bromide in drinking water sources (64, 80). Given the current regulatory climate and the fact that the majority of dissolved solids passes through these CWTs, it is expected that these treatment facilities will likely not play a major role in Marcellus Shale wastewater management.

The dominant wastewater management practice in the Marcellus Shale region nowadays is wastewater reuse for hydraulic fracturing [a review of Pennsylvania DEP data for the first 6 months of 2012 indicates 90% reuse rate (81)]. Wastewater is impounded at the surface and used directly, or after dilution or pretreatment. Reuse of wastewater minimizes the volume that must be treated and disposed, thus reducing environmental control costs and risks and enhancing the economic feasibility of shale-gas extraction (67). Currently, operators in the Marcellus region do not fully agree about the quality of wastewater that must be attained for reuse. Major concerns include possible precipitation of $BaSO_4$ and, to a lesser extent, $SrSO_4$ and $CaCO_3$ in the shale formation and the wellbore and the compatibility of wastewater with chemicals that are added to the fracturing fluid (such as friction reducers and viscosity modifiers). Hence, a better understanding of chemical compatibility issues would greatly improve the ability to reuse wastewater and minimize disposal volumes. In addition, radioactive radium that is commonly present in flowback/produced water will likely be incorporated in the solids that form in the wastewater treatment process and could yield a low-concentration radioactive waste that must be handled appropriately and has potential on-site human health implications.

The wastewater reuse program represents a somewhat temporary solution to wastewater management problems in any shale play. This program works only as long as there is net water consumption in a given well field. As the well field matures and the rate of hydraulic fracturing diminishes, the field becomes a net water producer because the volume of produced water will exceed the amount of water needed for hydraulic fracturing operations (82, 83). It is not yet clear how long it will take to reach that point in the Marcellus region, but it is clear that there is a need to develop additional technical solutions (such as effective and economical approaches for separation and use of dissolved salts from produced water and treatment for naturally occurring radioactive material) that would allow continued development of this important natural resource in an environmentally responsible manner. Considering very high salinity of many produced waters from shale gas development, this is truly a formidable challenge. Research focused on better understanding of where the salt comes from and how hydrofracturing might be designed to minimize salt return to the land surface would be highly beneficial.

Conclusions

Since the advent of hydraulic fracturing, more than 1 million hydraulic fracturing treatments have been conducted, with perhaps only one documented case of direct groundwater pollution resulting from injection of hydraulic fracturing chemicals used for shale gas extraction (54). Impacts from casing leakage, well blowouts, and spills of contaminated fluids are more prevalent but have generally been quickly mitigated (17). However, confidentiality requirements dictated by legal investigations, combined with the expedited rate of development and the limited funding for research, are substantial impediments to peer-reviewed research into environmental impacts. Furthermore, gas wells are often spaced closely within small areas and could result in cumulative impacts (5) that develop so slowly that they are hard to measure.

The public and government officials are continuing to raise questions and focus their attention on the issue of the exact composition of the hydrofracturing fluid used in shale formations. In 2010, the U.S. House of Representatives directed the EPA to conduct a study of hydraulic fracturing and its impact on drinking-water resources. This study will add important information to account for the fate of hydraulic fracturing fluid injected into the gas-bearing formation. It is well known that a large portion (as much as 90%) of injected fluid is not recovered during the flowback period, and it is important to document potential transport pathways and ultimate disposition of the injected fluid. The development of predictive methods to accurately account for the entire fluid volume based on detailed geophysical and geochemical characteristics of the formation would allow for the better design of gas wells and hydraulic fracturing technology, which would undoubtedly help alleviate public concerns. Research is also needed to optimize water management strategies for effective gas extraction. In addition, the impact of abandoned oil and gas wells on both fluid and gas migration is a concern that has not yet been adequately addressed.

Gas migration received considerable attention in recent years, especially in certain parts of the Appalachian basin (such as northeast Pennsylvania).

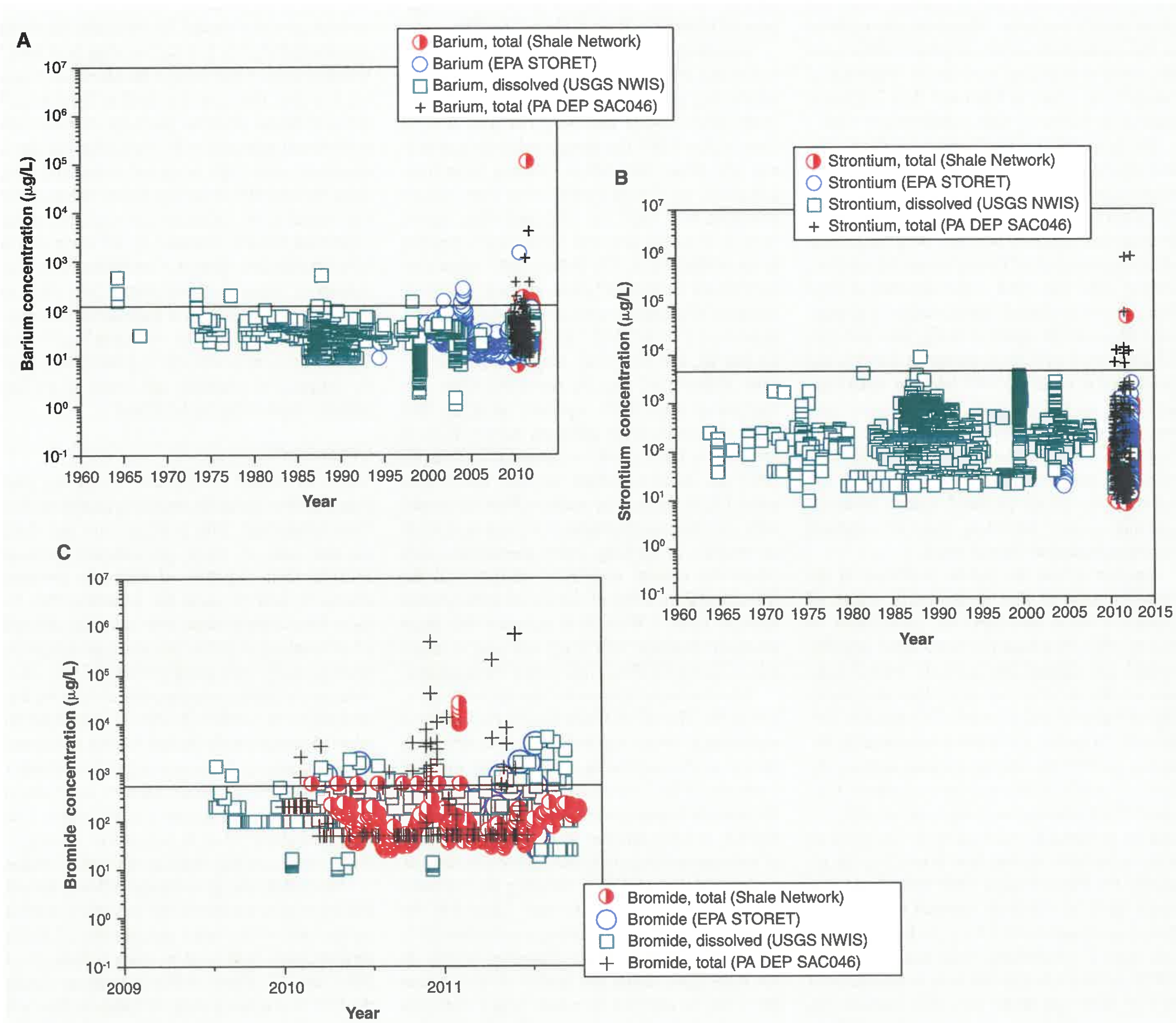


Fig. 4. Concentrations of three ions in surface waters of Pennsylvania in counties with unconventional shale-gas wells: (A) barium, (B) strontium, and (C) bromide. Data reported by EPA (STORET data), USGS (NWIS data), Susquehanna River Basin Commission, Appalachian Geological Consulting and ALLARM [from Shale Network database (*78*, *79*)], and from the Pennsylvania DEP (SAC046) include all rivers, streams, ponds, groundwater drains, lysimeter waters, and mine-associated pit, seep, and discharge waters accessed by using HydroDesktop (www.cuahsi.org) in the relevant counties (data before 2009 for bromide are not shown). Lines indicate 3σ above the mean of data from 1960 to 2003 for the longest duration dataset (USGS). Most values above the lines since 2003 represent targeted sampling in areas of known brine effluents from conventional oil and gas wells (such as Blacklick Creek receiving brine effluent from a CWT). The highest plotted Ba concentration was measured in Salt Springs in northern Pennsylvania. Three of the four samples with highest Sr and Br are from Blacklick Creek; next highest is from Salt Springs. Original values reported beneath the detection limit are plotted at that limit (10 to 100 μg Sr/L; 10 μg Ba/L; and 10 to 200 μg/L Br). The EPA maximum contaminant level (MCL) for Ba is 2000 μg/L. EPA reports no MCL for Sr or Br. Lifetime and 1-day health advisory levels for Sr are 4000 and 25000 μg/L, respectively, and a level under consideration for Br is 6000 μg/L.

It has been known for a long time that methane migrates from the subsurface (such as coal seams, glacial till, and black shales), and the ability to ignite methane in groundwater from private wells was reported long before the recent development of the Marcellus Shale (*14*). However, in the absence of reliable baseline information, it is easy to blame any such incidents on gas extraction activities. It is therefore critical to establish baseline conditions before drilling and to use multiple lines of evidence to better understand gas migration. It is also important to improve drilling and cementing practices, especially through gas-bearing formations, in order to eliminate this potential pathway for methane migration.

Water management for unconventional shale gas extraction is one of the key issues that will dominate environmental debate surrounding the gas industry. Reuse of flowback and produced water for hydraulic fracturing is currently addressing the concerns regarding the vast salt quantities that are brought to the surface (each Marcellus well generates as much as 200 tons of salt during the flowback period). However, there is a need for comprehensive risk assessment and regulatory oversight for spills and other accidental discharges of wastewater to the environment. As these well fields mature and the opportunities for wastewater reuse diminish, the need to find alternative management strategies for this wastewater will likely intensify. Now is the time to work on these issues in order to avoid an adverse environmental legacy similar to that from abandoned coal mine discharges in Pennsylvania.

References and Notes

1. U.S. Energy Information Administration, "Annual Energy Outlook 2013, Early Release" (U.S. Department of Energy, 2013); available at www.eia.gov/forecasts/aeo/erindex.cfm.
2. S. Holditch, K. Perry, J. Lee, "Unconventional Gas Reservoirs—Tight Gas, Coal Seams, and Shales, Working Document of the National Petroleum Council on Global Oil and Gas Study" (National Petroleum Council, 2007).
3. MIT, "The future of natural gas," http://mitei.mit.edu/publications/reports-studies/future-natural-gas. (Massachusetts Institute of Technology, 2011).
4. S. M. Olmstead, L. A. Muehlenbachs, J.-S. Shih, Z. Chu, A. J. Krupnick, *Proc. Natl. Acad. Sci. U.S.A.*, published online 11 March 2013. doi: 10.1073/pnas.1213871110
5. T. Engelder, *Fort Worth Basin Oil Gas Mag.* **20**, 18 (2009).
6. U.S. House of Representatives Committee of Energy and Commerce Minority Staff, "Chemicals used in Hydraulic Fracturing" (prepared for H. A. Waxman, E. J. Markey, D. DeGette, 2011).
7. S. Entrekin, M. Evans-White, B. Johnson, E. Hagenbuch, Rapid expansion of natural gas development poses a threat to surface waters. *Front. Ecol. Environ.* **9**, 503 (2011). doi: 10.1890/110053
8. P. J. Drohan, M. Brittingham, *Soil Sci. Soc. Am. J.* **76**, 1696 (20120).
9. Energy Information Administration, *Drilling Sideways–A Review of Horizontal Well Technology and Its Domestic Application, DOE/EIA-TR-0565* (U.S. Department of Energy, Washington, DC, 1993).
10. NYS DEC, "Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs" (New York State Department of Environmental Conservation, 2009).
11. www.FracFocus.org.
12. S. Hutson *et al.*, *Geol. Surv. Circ.* **1268**, 1 (2004).
13. A. W. Gorody, Factors affecting the variability of stray gas concentration and composition in groundwater. *Environ. Geosci.* **19**, 17 (2012). doi: 10.1306/eg.12081111013
14. S. S. Harrison, Evaluating system for ground-water contamination hazards due to gas-well drilling on the glaciated Appalachian plateau. *Ground Water* **21**, 689 (1983). doi: 10.1111/j.1745-6584.1983.tb01940.x
15. K. K. Eltschlager, J. W. Hawkins, W. C. Ehler, F. J. Baldassare, "Technical measures for the investigation and mitigation of fugitive methane hazards in areas of coal mining" (U.S. Dept. of the Interior, Office of Surface Mining Reclamation and Enforcement, Pittsburgh, PA, 2001).
16. K. M. Révész, K. J. Breen, F. J. Baldassare, R. C. Burruss, Carbon and hydrogen isotopic evidence for the origin of combustible gases in water-supply wells in north-central Pennsylvania. *Appl. Geochem.* **25**, 1845 (2010). doi: 10.1016/j.apgeochem.2010.09.011
17. T. Considine, R. Watson, N. Considine, J. Martin, "Environmental Impacts during Marcellus Shale Gas Drilling: Causes, Impacts, and Remedies, Report 2012-1" (Shale Resources and Society Institute, State University of New York, Buffalo, 2012).
18. Total count included violations 78.73A, 78.81D1 and D2, 78.83A and B, 78.83GRNDWTR, 78.83COALCSG, 78.84, 78.85, 78.86, and 207B. Wells with multiple violations were counted only once.
19. PA DEP Office of Oil and Gas, "Oil and Gas Compliance Report, www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_compliance_report/20299" (Pennsylvania Department of Oil and Gas, 2013).
20. S. G. Osborn, A. Vengosh, N. R. Warner, R. B. Jackson, Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proc. Natl. Acad. Sci. U.S.A.* **108**, 8172 (2011). doi: 10.1073/pnas.1100682108; pmid: 21555547
21. R. B. Jackson, S. G. Osborn, N. R. Warner, A. Vengosh, "Responses to frequently asked questions and comments about the shale-gas paper by Osborn *et al.*, June 15, 2011" (www.nicholas.duke.edu/cgc/FrackFAQ6_15_11.pdf, 2012).
22. S. C. Schon, Hydraulic fracturing not responsible for methane migration. *Proc. Natl. Acad. Sci. U.S.A.* **108**, E664 (2011).
23. R. J. Davies, Methane contamination of drinking water caused by hydraulic fracturing remains unproven. *Proc. Natl. Acad. Sci. U.S.A.* **108**, E871 (2011).
24. L. J. Molofsky, J. A. Connor, S. K. Farhat, A. S. Wylie Jr., T. Wagner, *Oil Gas Dev.* **109**, 54 (2011).
25. C. D. Laughrey, F. J. Baldassare, *Am. Assoc. Pet. Geol. Bull.* **82**, 317 (1998).
26. M. J. Whiticar, Carbon and hydrogen isotope systematics of bacterial formation and oxidation of methane. *Chem. Geol.* **161**, 291 (1999). doi: 10.1016/S0009-2541(99)00092-3
27. G. Etiope, A. Drobniak, A. Schimmelmann, *Marine and Petroleum Geology*, http://dx.doi.org/10/1016/j.marpetgeo.2013.02.009 (2013).
28. K. J. Breen, K. Revesz, F. J. Baldassare, S. D. McAuley, "Natural gases in ground water near Tioga Junction, Tioga County, North-central Pennsylvania–Occurrence and use of isotopes to determine origins, 2005" (U.S. Geological Survey, Scientific Investigations Report Series 2007-5085, 2007).
29. PA DEP, "Oil and Gas Well Drilling and Production in Pennsylvania" (Pennsylvania Department of Environmental Protection, PA DEP Fact Sheet, 2011).
30. W. R. Gough, B. A. Waite, in *Water Resources in Pennsylvania: Availability, Quality, and Management*, S. K. Majumdar, E. W. Miller, R. R. Parizek, Eds. (Pennsylvania Academy of Science, 1990), pp. 384–398.
31. IOGC, "Protecting our Country's Resources: The States' Case, Orphaned Well Plugging Initiative" (Interstate Oil and Gas Compact Commission, National Energy Technology Laboratory, 2008).
32. S. G. Osborn, J. C. McIntosh, Chemical and isotopic tracers of the contribution of microbial gas in Devonian organic-rich shales and reservoir sandstones, northern Appalachian Basin. *Appl. Geochem.* **25**, 456 (2010). doi: 10.1016/j.apgeochem.2010.01.001
33. E. W. Boyer, B. R. Swistock, J. Clark, M. Madden, D. E. Rizzo, "The impact of Marcellus gas drilling on rural drinking water supplies" (The Center for Rural Pennsylvania, Pennsylvania General Assembly, www.rural.palegislature.us/documents/reports/Marcellus_and_drinking_water_2011_rev.pdf, 2012).
34. N. R. Warner *et al.*, Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania. *Proc. Natl. Acad. Sci. U.S.A.* **109**, 11961 (2012). doi: 10.1073/pnas.1121181109; pmid: 22778445
35. T. M. Kresse *et al.*, *U.S.G.S. Scientific Investigations Report 2012-5273* (2012).
36. G. Bol, H. Grant, S. Keller, F. Marcassa, J. de Rozieres, *Oilfield Rev.* **3**, 35 (1991).
37. A. Bonnett, D. Pafitis, *Oilfield Rev.* **8**, 36 (1996).
38. V. Gonzalo, B. Aiskely, C. Alicia, in *SPE Latin American and Caribbean Petroleum Engineering Conference, Society of Petroleum Engineers International* (Rio de Janeiro, Brazil, 2005).
39. M. J. Rogers, R. L. Dillenbeck, R. N. Eid, *Society of Petroleum Engineers*, 90829 (2004).
40. M. B. Dusseault, M. N. Gray, *Society of Petroleum Engineers*, 64733 (2000).
41. J. M. Tinsley, E. C. Miller, D. L. Sutton, *Society of Petroleum Engineers*, 8257 (1979).
42. T. D. Hayes, "Marcellus Shale water chemistry" (Appalachian Shale Water Conservation and Management Committee, 2009).
43. J.-P. Nicot, B. R. Scanlon, Water use for Shale-gas production in Texas, U.S. *Environ. Sci. Technol.* **46**, 3580 (2012). doi: 10.1021/es204602t; pmid: 22385152
44. D. Soeder, W. M. Kappell, "Water resources and natural gas production from the Marcellus Shale" (U.S. Geological Survey Fact Sheet 2009-3032, Reston, VA, 2009).
45. B. G. Rahm, S. J. Riha, Toward strategic management of shale gas development: Regional, collective impacts on water resources. *Environ. Sci. Policy* **17**, 12 (2012). doi: 10.1016/j.envsci.2011.12.004
46. E. Barbot, N. S. Vidic, K. B. Gregory, R. D. Vidic, Spatial and Temporal Correlation of Water Quality Parameters of Produced Waters from Devonian-Age Shale following Hydraulic Fracturing. *Environ. Sci. Technol.* **47**, 2562 (2013). doi: 10.1021/es304638h; pmid: 23425120
47. L. O. Haluszczak, A. W. Rose, L. R. Kump, Geochemical evaluation of flowback brine from Marcellus gas wells in Pennsylvania, USA. *Appl. Geochem.* **28**, 55 (2013). doi: 10.1016/j.apgeochem.2012.10.002
48. P. E. Dresel, A. W. Rose, Pennsylvania Geological Survey, 4th series Open File Report OFOG 10-01.0, www.dcnr.state.pa.us/topogeo/pub/openfile/ofog10_01.aspx (2010), p. 48.
49. M. E. Blauch, R. R. Myers, T. R. Moore, B. A. Lipinski, N. A. Houston, paper presented at the SPE Eastern Regional Meeting, Society of Petroleum Engineers SPE 125740, Charleston, WV, 2009.
50. E. L. Rowan, M. A. Engle, C. S. Kirby, T. F. Kraemer, "Radium content of oil- and gas-field produced waters in the Northern Appalachian Basin (USA): Summary and discussion of data" (U.S. Geological Survey, Scientific Investigation Report 2011-5135, 2011).
51. M. E. Mantell, in *EPA Hydraulic Fracturing Study Technical Workshop 4. Water Resources Management, Chesapeake Energy* (Oklahoma City, OK, 2011).
52. T. Myers, Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water* **50**, 872 (2012). doi: 10.1111/j.1745-6584.2012.00933.x; pmid: 22509908
53. D. C. DiGiulio, R. T. Wilkin, C. Miller, G. Oberly, "DRAFT: Investigation of Ground Water Contamination near Pavillion, Wyoming" (U.S. Environmental Prodection Agency Office of Research and Development, 2011).
54. U.S. Environmental Protection Agency, "Report to Congress: Management of wastes from the exploration, development, and production of crude oil, natural gas, and geothermal energy" (U.S. Environmental Protection Agency, Washington, DC, 1987).
55. T. Engelder, in *GSA Annual Meeting and Exposition* (Charlotte, NC, 2012); available at https://gsa.confex.com/gsa/2012AM/webprogram/Paper207549.html.
56. T. Engelder, Capillary tension and imbibition sequester frack fluid in Marcellus gas shale.. *Proc. Natl. Acad. Sci. U.S.A.* **109**, E3625 (2012). doi: 10.1073/pnas.1216133110
57. K. Fisher, N. Warpinski, *SPE Prod. Oper.* **27**, 8 (2012).
58. P. R. Wright, P. B. McMahon, D. K. Mueller, M. L. Clark, "Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming, April and May 2012" (U.S.G.S. Data Series 718, http://pubs.usgs.gov/ds/718/DS718_508.pdf, 2012).
59. J. E. Saiers, E. Barth, Potential contaminant pathways from hydraulically fractured shale aquifers. *Ground Water* **50**, 826, discussion 828 (2012). doi: 10.1111/j.1745-6584.2012.00990.x; pmid: 23003107
60. K. R. Bruner, R. A. Smosna, "Comparative study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin, DOE/NETL-2011/1478" (Department of Energy, National Energy Technology Laboratory, 2011).
61. C. W. Poth, *Pennsylvania Geol. Surv. Bull.* **M47**, 1 (1962).
62. J. A. Williams, *U.S. Geological Survey Scientific Investigations Report 2010-5224* (2010).
63. US DOE, "Cost-Effective Recovery of Low-TDS Frac Flowback Water for Re-use" (U.S. Department of Energy, www.netl.doe.gov, 2011).
64. J. M. Wilson, J. M. VanBriesen, *Environ. Pract.* **14**, 288 (2012). doi: 10.1017/S1466046612000427
65. B. D. Lutz, A. N. Lewis, M. W. Doyle, Generation, transport, and disposal of wastewater associated with Marcellus Shale gas development. *Water Resour. Res.* **49**, 647 (2013). doi: 10.1002/wrcr.20096
66. D. M. Kargbo, R. G. Wilhelm, D. J. Campbell, Natural gas plays in the Marcellus Shale: challenges and potential opportunities. *Environ. Sci. Technol.* **44**, 5679 (2010). doi: 10.1021/es903811p; pmid: 20518558
67. K. B. Gregory, R. D. Vidic, D. A. Dzombak, Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing. *Elements* **7**, 181 (2011). doi: 10.2113/gselements.7.3.181

68. C. E. Clark, J. A. Veil, "Produced Water Volumes and Management Practices in the United States, ANL/EVS/R-09/1" (Environmental Science Division, Argonne National Laboratory, 2009).
69. C. J. de Pater, S. Baisch, "Geomechanical study of Bowland Shale seismicity, Synthesis Report" (Cuadrilla Resources, Ltd., 2011).
70. Reuters, "Ohio earthquake was not a natural event, expert says," *Reuters*, 2012.
71. National Academy of Sciences, *Induced Seismicity Potential in Energy Technologies* (National Academies Press, Washington, DC, 2012).
72. Texas Department of Agriculture, "Agricultural Land and Water Contamination from Injection Wells, Disposal Pits, and Abandoned Wells Used in Oil and Gas Production" (TX Department of Agriculture, Department of Natural Resources, 1985).
73. K. J. Ferrar *et al.*, *Environmental Science & Technology*, dx.doi.org/10.1021/es301411q (2013).
74. D. J. Rozell, S. J. Reaven, Water pollution risk associated with natural gas extraction from the Marcellus Shale. *Risk Anal.* **32**, 1382 (2012). doi: 10.1111/j.1539-6924.2011.01757.x; pmid: 22211399
75. PA DEP, "Wastewater Treatment Requirements, 25 PA Code 95" (Pennsylvania Department of Environmental Protection, 2010).
76. J. R. Mullaney, D. L. Lorenz, A. D. Arntson, "Chloride in Groundwater and Surface Water in Areas Underlain by the Glacial Aquifer System, Northern United States" (U.S. Department of the Interior, U.S. Geological Survey, Scientific Investigations Report 2009-5086, 2009).
77. E. C. Chapman *et al.*, Geochemical and strontium isotope characterization of produced waters from Marcellus Shale natural gas extraction. *Environ. Sci. Technol.* **46**, 3545 (2012). doi: 10.1021/es204005g; pmid: 22360406
78. S. L. Brantley, C. Wilderman, J. Abad, Workshop discusses database for Marcellus water issues. *Eos Trans. AGU* **93**, 328 (2012). doi: 10.1029/2012EO340006
79. Shale Network database is accessible through HydroDesktop (www.cuahsi.org).
80. S. States *et al.*, paper presented at the AWWA-WQTC, Phoenix, AZ, November 13 to 17, 2011.
81. K. O. Maloney, D. A. Yoxtheimer, Production and Disposal of Waste Materials from Gas and Oil Extraction from the Marcellus Shale Play in Pennsylvania. *Environ. Pract.* **14**, 278 (2012). doi: 10.1017/S146604661200035X
82. C. Kuijvenhoven *et al.*, paper presented at the Shale Gas Water Management Conference, Dallas, TX, November 30 to December 1, 2011.
83. R. D. Vidic, T. D. Hayes, S. Hughes, in *Shale Gas Water Management Marcellus Initiative* (Pittsburgh, PA, 2011).
84. W. M. Kappell, E. A. Nystrom, Dissolved methane in New York groundwater, 1999–2011. U.S. Geological Survey Open-File Report 2012-1162 (2012); available at http://pubs.usgs.gov/of/2012/1162.
85. J. S. White, M. V. Mathes, "Dissolved-gas concentrations in ground water in West Virginia" (U.S. Geological Survey Data Series 156, 2006).

Acknowledgments: R.D.V., S.L.B., D.Y., and J.D.A. acknowledge funding for the Shale Network from NSF grant OCE-11-40159.

10.1126/science.1235009

Marine and Petroleum Geology 56 (2014) 239–254

Contents lists available at ScienceDirect

Marine and Petroleum Geology

journal homepage: www.elsevier.com/locate/marpetgeo

Review article

Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation

Richard J. Davies [a,*], Sam Almond [a], Robert S. Ward [b], Robert B. Jackson [c,d], Charlotte Adams [a], Fred Worrall [a], Liam G. Herringshaw [a], Jon G. Gluyas [a], Mark A. Whitehead [e]

[a] Durham Energy Institute, Department of Earth Sciences, Durham University, Science Labs, Durham DH1 3LE, UK
[b] Groundwater Science Directorate, British Geological Survey, Keyworth, Nottingham NG12 5GG, UK
[c] School of Earth Sciences, Woods Institute for the Environment, and Precourt Institute for Energy, Stanford University, Stanford, CA 94305, USA
[d] Nicholas School of the Environment, Division of Earth and Ocean Sciences, Duke University, Box 90338, 124 Science Drive, Durham, NC 27708-0338, USA
[e] Ward Hadaway, Sandgate House, 102 Quayside, Newcastle Upon Tyne NE13DX, UK

ARTICLE INFO

Article history:
Received 8 December 2013
Received in revised form
28 February 2014
Accepted 1 March 2014
Available online 25 March 2014

Keywords:
Shale
Fracking
Integrity
Barrier
Integrity
Wells

ABSTRACT

Data from around the world (Australia, Austria, Bahrain, Brazil, Canada, the Netherlands, Poland, the UK and the USA) show that more than four million onshore hydrocarbon wells have been drilled globally. Here we assess all the reliable datasets (25) on well barrier and integrity failure in the published literature and online. These datasets include production, injection, idle and abandoned wells, both onshore and offshore, exploiting both conventional and unconventional reservoirs. The datasets vary considerably in terms of the number of wells examined, their age and their designs. Therefore the percentage of wells that have had some form of well barrier or integrity failure is highly variable (1.9%–75%). Of the 8030 wells targeting the Marcellus shale inspected in Pennsylvania between 2005 and 2013, 6.3% of these have been reported to the authorities for infringements related to well barrier or integrity failure. In a separate study of 3533 Pennsylvanian wells monitored between 2008 and 2011, there were 85 examples of cement or casing failures, 4 blowouts and 2 examples of gas venting. In the UK, 2152 hydrocarbon wells were drilled onshore between 1902 and 2013 mainly targeting conventional reservoirs. UK regulations, like those of other jurisdictions, include reclamation of the well site after well abandonment. As such, there is no visible evidence of 65.2% of these well sites on the land surface today and monitoring is not carried out. The ownership of up to 53% of wells in the UK is unclear; we estimate that between 50 and 100 are orphaned. Of 143 active UK wells that were producing at the end of 2000, one has evidence of a well integrity failure.

1. Introduction

The rapid expansion of shale gas and shale oil exploration and exploitation using hydraulic fracturing techniques has created an energy boom in the USA but raised questions regarding the possible environmental risks, such as the potential for groundwater contamination (e.g. Jackson et al., 2013; Vidic et al., 2013) and fugitive emissions of hydrocarbons into the atmosphere (e.g. Miller et al., 2013).

Boreholes drilled to explore for and extract hydrocarbons must penetrate shallower strata before reaching the target horizons. Some of the shallower strata may contain groundwater used for human consumption or which supports surface water flows and wetland ecosystems. Although it has been routine practice to seal wells passing through such layers, they remain a potential source of fluid mixing in the subsurface and potential contamination (King and King, 2013). This can occur for many reasons, including poor well completion practices, the corrosion of steel casing, and the deterioration of cement during production or after well abandonment. Boreholes can then become high-permeability potential conduits for both natural and man-made fluids (e.g. Watson and Bachu, 2009), and vertical pressure gradients in the subsurface can drive movement of fluids along these flow paths. The potential importance of wellbore integrity to the protection of shallow groundwater has recently been highlighted in research papers and reports (e.g. Osborn et al., 2011; The Royal Society & The Royal

* Corresponding author. Tel.: +44 1913342346.
E-mail address: richard.davies@dur.ac.uk (R.J. Davies).

http://dx.doi.org/10.1016/j.marpetgeo.2014.03.001

Glossary

BCF	Billion Cubic Feet
BCM	Billion Cubic Metres
BRGM	Bureau de Recherches Géologiques et Minières, France
BDEP	Brazilian Database of Exploration and Production
CA	California
CO_2	Carbon Dioxide
CCTV	Closed-Circuit Television
DECC	Department of Energy and Climate Change, UK
DEFRA	Department of Environment, Food and Rural Affairs, UK
DEP	Department of Environmental Protection, USA
EIA	Energy Information Administration, USA
ERCB	Energy Resources Conservation Board, Canada
EUR	Estimated Ultimate Recovery
GM	Gas Migration
GoM	Gulf of Mexico
IPCC	Intergovernmental Panel on Climate Change
km^2	Square Kilometres
M	Metres
m^3	Cubic Metres
mD	Milli-Darcies
NOCS	Norwegian Offshore Continental Shelf
NY	New York
PA	Pennsylvania
PSA	Petroleum Safety Authority, Norway
RRC	Railroad Commission, Texas
SCVF	Surface Casing Vent Flow
SINTEF	Norwegian Foundation for Scientific and Industrial Research
TCF	Trillion Cubic Feet
TCM	Trillion Cubic Metres
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
UKOGL	United Kingdom Onshore Geophysical Library
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USA	United States of America
WFD	Water Framework Directive, Europe
WV	West Virginia

Academy of Engineering Report (2012); Jackson et al., 2013; King and King, 2013). In addition to protecting ground and surface waters, effective well sealing prevents leakage of methane and other gases into the atmosphere. This is important as methane is 86 times more effective than CO_2 at trapping heat in the atmosphere over a 20-year period and 34 times more effective over a century (IPCC, 2013). Well barrier and integrity failures can occur during drilling, production, or after abandonment; in rare examples, including in the USA, well leakage has led to explosions at the Earth's surface (e.g. Miyazaki, 2009).

This paper has four aims: 1) to estimate the number of onshore hydrocarbon wells globally; 2) to explain how onshore wells are categorised (e.g. producing, abandoned, idle, orphaned) and what statistical data are available on the numbers of wells in these groups; 3) to document the number of wells that are known to have had some form of well barrier and/or integrity failure, placing these numbers in the context of other extractive industries; and 4) to analyse how many onshore wells in the UK can be easily accessed to assess for barrier and integrity failure. For well barrier and integrity failure our approach has been to include all the reliable datasets that are available, rather than de-select any data. This inclusive approach has the draw-back that the data we present include wells of different age, of different designs and drilled into different geology. Unsurprisingly there is a significant spread in the statistics on the percentage of wells that have well barrier or integrity failure.

The review is largely focused on North America, as it has a long history of onshore hydrocarbon drilling (including wells drilled for shale gas and shale oil) and the UK, which contrasts in having a mature offshore drilling industry, but relatively little onshore drilling. It mainly, but not exclusively, covers static well failure (i.e. after drilling operations are completed), and summarises currently available data for regulators, non-government organisations, the public, and the oil and gas industry.

1.1. Barrier systems

Barriers are containment mechanisms within a well or at the well head that are designed to withstand the corrosion, pressures, temperatures and exposure times associated with the phases of drilling, production and well abandonment. The types of barriers used to prevent contamination of groundwater, surface water, soils, rock layers and the atmosphere depend on whether the well is for exploration or production, but generally include cement, casing, valves and seals (Fig. 1). Barriers can be nested, so that a well has several in place. They can be dynamic (e.g. a valve) or static (e.g. cement), and may or may not be easily accessible for assessment or monitoring (see King and King, 2013).

Drilling a well for exploration or production is a multistage process during which the upper parts of a borehole, once drilled, are sealed with steel casing and cemented into place. Cement was introduced to the petroleum industry as early as 1903, when Frank Hill of Union Oil Co. poured 50 sacks of Portland cement into a well to seal off water-bearing strata (Smith, 1976). Cementing is now typically carried out by pumping water-cement slurries down the casing to the bottom of the hole, displacing drilling fluids from the casing-rock and other annuli, leaving a sheath of cement to set and harden (Fig. 1). The integrity of these seals is pressure-tested before the next stage of drilling occurs. Only if the well passes these pressure tests will drilling continue. If the well fails the test, the casing is re-cemented before drilling continues. The sizes and lengths of casing, and the depths at which different casings are used depend upon the geology, the importance or sensitivity of the groundwater that the well penetrates, and the purpose of the well (Fig. 1). Well completion should follow statutory regulations and/or industry best practice. When a well is abandoned, cement is normally pumped into the production tubing to form a cement plug to seal it. Commonly (e.g. in the UK), the top of the well is welded shut.

1.2. Terminology

The terms 'well barrier failure' and 'well integrity failure' were differentiated by King and King (2013). They used 'well integrity failure' for cases where all well barriers fail, establishing a pathway that enables leakage into the surrounding environment (e.g. groundwater, surface water, underground rock layers, soil, atmosphere). 'Well barrier failure' was used to refer to the failure of individual or multiple well barriers (e.g. production tubing, casing, cement) that has not resulted in a detectable leak into the surrounding environment. The same terminology is used in this paper:

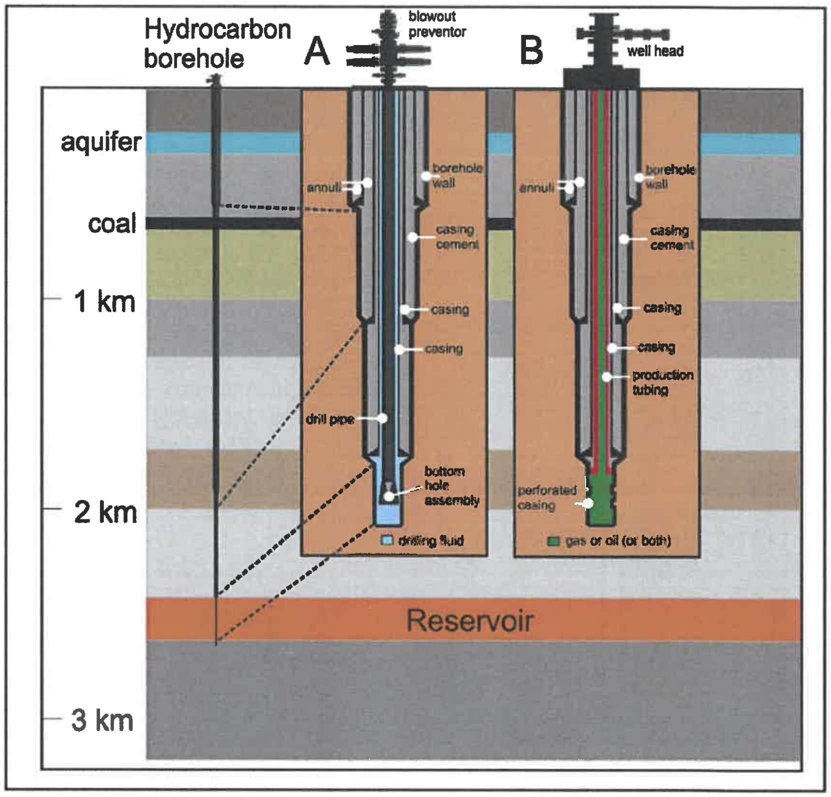


Figure 1. Schematic diagram of typical well design, showing (A): structure of an exploration well; and (B): a production well. Depths to which different casings are used vary according to geology and pressure regime of drill site. Well diameter exaggerated to show sections more clearly.

'well integrity failure' includes cases when gas or fluids are reported to have leaked into soils, rock strata or the atmosphere, and 'well barrier failure' includes cases where a barrier failure has occurred but there is no information that indicates that fluids have leaked out of the well.

1.3. Routes and driving mechanisms

For a well to leak, there must be a source of fluid (Fig. 2), a breakdown of one or more well barriers, and a driving force for fluid movement, which could be fluid buoyancy or excess pore pressure due to subsurface geology (e.g. Watson and Bachu, 2009). There are seven subsurface pathways by which leakage typically occurs (Figs. 3, 4). These pathways include the development of channels in the cement, poor removal of the mud cake that forms during drilling, shrinkage of cement, and the potential for relatively high cement permeability (e.g. Dusseault et al., 2000). There are other mechanisms that can operate in specific geological settings. Reservoir compaction during production, for example, can cause shear failure in the rocks and casing above the producing reservoir (Marshall and Strahan, 2012; route 7 marked on Fig. 3). Leaking wells can also connect with pre-existing geological faults, enabling leakage to reach the surface (Chillingar and Endres, 2005). A range of fluids can leak, for instance formation fluids, water, oil and gas, and they can move through or out of the well bore by advective or diffusive processes (e.g. Dusseault et al., 2000). Overpressure may be the driving force for fluid flow (e.g. the Hatfield blow-out near Doncaster, UK; Ward et al., 2003), but hydrostatically pressured successions can also feed leaking wells, with fluids migrating due to buoyancy and diffusion.

A leak can be catastrophic, as seen in cases such as the recent blowout of a Whiting Petroleum Corp oil well (Cherry State 31-16H) in North Dakota (North Dakota Department of Health (2014)) and rare examples of explosions in urban areas (Chillingar and Endres, 2005), or be at sufficiently low rates to be barely detectable. The fluid sources can be hydrocarbon reservoirs (e.g. Macondo, Gulf of Mexico); non-producing permeable formations (e.g. Marshall and Strahan, 2012); coal seams (e.g. Beckstrom and Boyer, 1993; Cheung et al., 2010); and biogenic or thermogenic gases from shallow rock formations (e.g. Traynor and Sladen, 1997; Jackson et al., 2013). Oil or gas emissions can seep to the surface, though leaking methane can be oxidised by processes such as bacterial sulphate reduction (e.g. Van Stempvoort et al., 2005). Well failures can potentially occur in any type of hydrocarbon borehole, whether it is being drilled, producing hydrocarbons, injecting fluid into a reservoir, or has been abandoned.

Wells can be tested at the surface for well barrier failure and well integrity failure by determining whether or not there is pressure in the casing at the surface. This is referred to as sustained casing pressure (e.g. Watson and Bachu, 2009), but does not necessarily prove which barrier has failed or its location. Channels in cement, which are potential leakage pathways, can be detected by running detection equipment down the borehole. Migration of fluids outside the well is established by inserting a probe into the soil immediately surrounding the well bore, or by sampling groundwater nearby, hydraulically down-gradient of the well. Poor cement barriers can be identified by a number of methods (e.g. ultrasonic frequency detection; Johns et al., 2011) and can be repaired in some cases, using cement or pressure-activated sealants (e.g. Chivvis et al., 2009).

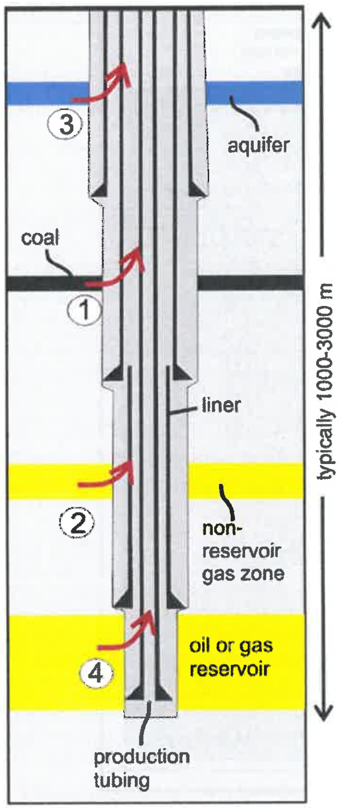


Figure 2. Schematic diagram of typical sources of fluid that can leak through a hydrocarbon well. 1 – gas-rich formation such as coal; 2 – non-producing, gas- or oil-bearing permeable formation; 3 – biogenic or thermogenic gas in shallow aquifer; and 4 – oil or gas from an oil or gas reservoir.

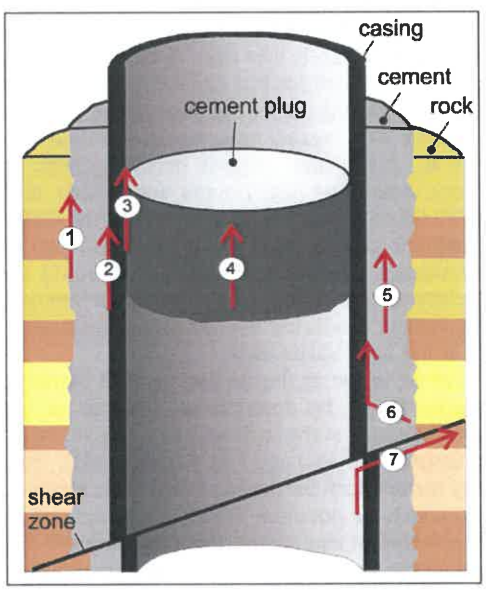


Figure 3. Routes for fluid leak in a cemented wellbore. 1 – between cement and surrounding rock formations, 2 – between casing and surrounding cement, 3 – between cement plug and casing or production tubing, 4 – through cement plug, 5 – through the cement between casing and rock formation, 6 – across the cement outside the casing and then between this cement and the casing, 7 – along a sheared wellbore. After Celia et al. (2005) and this paper.

2. Datasets

This paper draws on a variety of datasets, mostly published, but in some instances sourced from online repositories or national databases, and follows the approach of Davies et al. (2013). In that study, the risk of induced seismicity due to hydraulic fracturing was reviewed, and intentionally included all datasets in the public domain that were considered to be reliable, rather than de-selecting any data (Davies et al., 2013). This inclusive approach has a drawback because well barrier and well integrity failure frequencies are probably specific to the geology, age of wells, and era of well construction (King and King, 2013). A wide range of failure statistics is therefore reported, and although they are presented on a single graph to show the spread of results (Fig. 9), this is not intended to imply that direct comparisons between very different datasets (i.e. size, age of wells, geology) can be made.

The sources we used do not report their findings consistently and it is unclear in some cases whether well barrier failures have led to leaks into groundwater, rock layers, soil or the atmosphere,

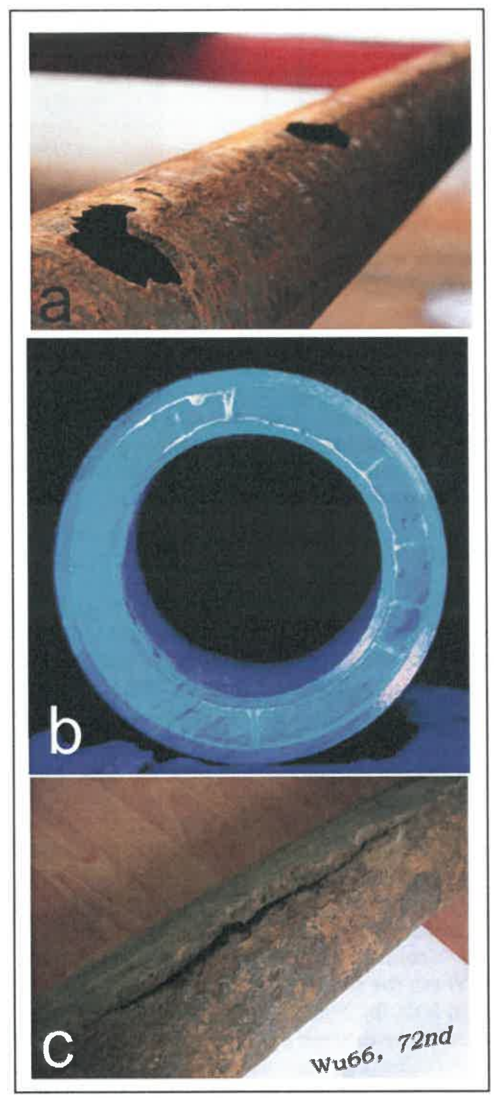


Figure 4. Photographic examples of leak pathways: (a) Corrosion of tubing (Torbergsen et al., 2012); (b) Cracks in cement (Crook et al., 2003); (c) Corrosion of casing (Xu et al., 2006).

producing a true well integrity failure. To be as clear as possible, well barrier and well integrity failure are distinguished in Table 3, quoting directly from the sources used and, where possible, providing additional information on the age of the well and when the monitoring was carried out.

To locate hydrocarbon wells drilled onshore in the UK since 1902 (the age of the earliest well recorded by DECC), the United Kingdom Onshore Geophysical Library (UKOGL) map of well locations was used (UKOGL, 2013), coupled with satellite imagery from Google Earth. A visual inspection and categorisation of the locations was carried out to assess whether the wells have a physical presence at the surface. Pollution incident data were provided by the Environment Agency (England); these data were used to identify incidents that occurred in close proximity to known well sites.

3. Global well inventory

As shale gas and oil exploitation has been carried out primarily onshore to date, the global well inventory in this study reports only the number of hydrocarbon wells drilled onshore, as this provides a more relevant historical context. Data in the public domain were used, sourced either from published reports or from online datasets populated by regulatory authorities. Several comprehensive review papers were also utilised, particularly those addressing the potential of CO_2 to leak upwards through wells (e.g. Watson and Bachu, 2009).

A graph of wells drilled per year since the 1930s in Australia, Brazil,the Netherlands, Poland, the UK, and the USA shows that some countries, such as the UK, have very modest onshore drilling activity compared to others such as the USA (Fig. 5). Historical data are sparse, so it is difficult to estimate the total number of onshore hydrocarbon wells drilled globally, but in the USA alone, at least 2.6 million wells have been drilled since 1949 (EIA database). Former Soviet countries such as Azerbaijan, where many thousands of wells have been drilled, are not included in this study due to a lack of access to adequate data. Nonetheless, taking into consideration those drilled only in Australia, Austria, Bahrain, Brazil, Canada, the Netherlands, Poland, the UK and the USA, we estimate there are at least 4 million onshore hydrocarbon wells (Table 1).

4. Well integrity

4.1. Pennsylvania, USA

The online database collated by the Department of Environmental Protection (DEP) in the US state of Pennsylvania allows oil and gas well records to be searched by various criteria, such as well status, operator and drilling date. The unconventional hydrocarbon wells included in that database are those that were drilled to target the Marcellus Shale Formation. From these data, Vidic et al. (2013) derived a figure of 3.4% well barrier leakage for shale gas production sites in Pennsylvania (219 violations for 6466 wells) between 2008 and 2013. Using the same database, Ingraffea (2012) argued that 211 (6.2%) of 3391 shale gas wells drilled in Pennsylvania in 2011 and 2012 had failed. More recently, Considine et al. (2013) identified 2.58% of 3533 individual wells as having some form of barrier or integrity failure. This consisted of 0.17% of wells having experienced blowouts (4 wells), venting or gas migration (2), and 2.41% having experienced casing or cementing failures. Measurable concentrations of gas were present at the surface for most wells with casing or cementing violations. Figure 6 shows a breakdown of the 1144 environmental violations issues for the 3533 wells.

Table 1
Number of hydrocarbon boreholes drilled onshore in selected nation states.

Country	Number of wells	Source
UK	2152	DECC, 2013
Canada–Alberta	316,439	Watson and Bachu (2009)
Bahrain	750	Sivakumar and Janahi (2004)
USA	2,581,782	EIA Database
Austria	1200	Veron (2005)
Netherlands	3231	Geological Survey of the Netherlands
Brazil	21,301	Brazil Database of Exploration and Production (BDEP)
Australia	9903	Geoscience Australia
Poland	7052	Polish Geological Institute

In this study, the search criteria used to categorise leakage incidents in Pennsylvania followed the approach described by Ingraffea (2012) and are based on code violations reported during site inspections. Code violations that would constitute a well failure are those likely to result in a significantly increased risk of contaminants reaching either the surface or potable water sources. They include: (a) failure to case and cement the well properly; (b) excessive casing seat pressure; (c) failure to case and cement sufficiently to prevent migrations into fresh groundwater; and (d) insufficient cement and steel casings between the wellbore and the near-surface aquifer to prevent seepage of fluids. Using the Pennsylvania state database, a well barrier or integrity failure rate of 6.3% is identified for the years 2005–2013. This includes failures noted in inspection reports that were not recorded as a violation, following the methodology of Ingraffea (2012). Without including these reports, the failure rate would be 5%. This is higher than the 3.4% well leakage figure reported by Vidic et al. (2013) for the period 2008–2013, and close to the well failure rate of 6.2% reported by Ingraffea (2012).

4.2. Gulf of Mexico, USA

Data from the US Minerals Management Service show that, of 15,500 producing, shut in and temporarily abandoned wells in the

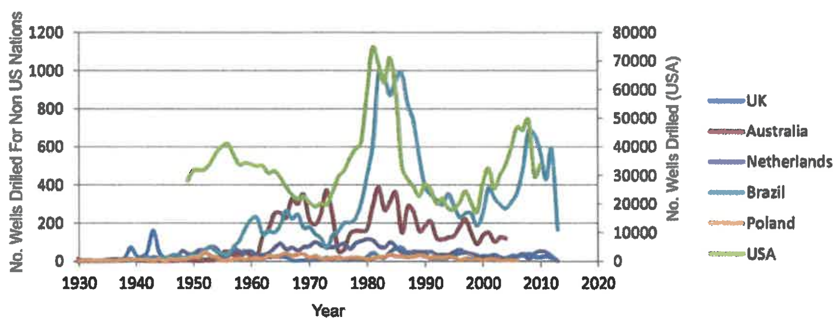


Figure 5. Number of wells drilled annually since the 1930s in Australia, Brazil, Netherlands, Poland, the UK and the USA. Sources: DECC, 2013; Geoscience Australia; Geological Survey of the Netherlands; Brazil Database of Exploration and Production (BDEP); EIA, Polish Geological Institute.

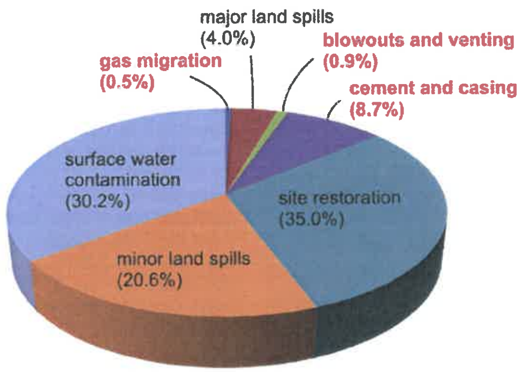


Figure 6. Breakdown of 1144 notices of violations from 3533 wells in Pennsylvania from 2008 to 2011 (after Considine et al., 2013). Red font indicates those related to well barrier and integrity failure. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

outer continental shelf of the Gulf of Mexico, 6692 (43%) have sustained casing pressure on at least one casing annulus (Brufatto et al., 2003). Of these incidents, 47.1% occurred in the production strings, 26.2% in the surface casing, 16.3% in the intermediate casing, and 10.4% in the conductor pipe.

4.3. Offshore Norway

Vignes and Aadnøy (2010) examined 406 wells at 12 Norwegian offshore facilities operated by 7 companies. Their dataset included producing and injection wells, but not plugged and abandoned wells. Of the 406 wells they examined, 75 (18%) had well barrier issues. There were 15 different types of barrier that failed, many of them mechanical (Fig. 7), including the annulus safety valve, casing, cement and wellhead. Issues with cement accounted for 11% of the failures, whilst issues with tubing accounted for 39% of failures.

The PSA has also performed analyses of barrier failures and well integrity on the Norwegian continental shelf. Its analysis showed that, in 2008, 24% of 1677 wells were reported to have well barrier failures; in 2009, 24% of 1712 wells had well barrier failures; and in 2010, 26% of 1741 wells had well barrier failures. It is unclear whether the same wells were tested in successive years or whether surveys targeted different wells (Vignes, 2011). A study of 217 wells in 8 offshore fields was also carried out by SINTEF (see Vignes, 2011). Between 11% and 73% of wells had some form of barrier failure, with injectors 2 to 3 times more likely to fail than producers (Vignes, 2011).

At the 20th Drilling Conference in Kristiansand, Norway, in 2007, Statoil presented an internal company survey of offshore well integrity (Vignes, 2011). This analysis showed that 20% of 711 wells had integrity failures, issues, or uncertainties (Vignes, 2011). When subdivided into production and injection wells, the survey concluded that 17% of 526 production wells and 29% of 185 injection wells had well barrier failures.

4.4. Onshore Netherlands

The results of an inspection project carried out by the State Supervision of Mines Netherlands were also reported by Vignes (2011). Their inspections, carried out in 2008, included only 31 wells from a total of 1349 development wells from 10 operating companies. Of those wells, 13% (4 of 31) had well barrier problems; by well type, problems were identified in 4% of the production wells (1 of 26) and 60% of the injection wells (3 of 5).

4.5. Offshore and onshore UK

For offshore wells on the UKCS, Burton (2005) found that 10% of 6137 wells (operated by 18 companies) had been shut-in (valves at the well head closed) during the last five years as a result of 'structural integrity issues'. The total number of wells drilled on the UKCS is 9196; exploration boreholes that did not make commercial discoveries were not included in the Burton (2005) study.

Onshore, 2152 hydrocarbon wells have been drilled in the UK between 1902 and 2013. Although the onshore sedimentary succession is not thought to be overpressured, hydrocarbons could still migrate upwards because of their buoyancy relative to pore water or the fluid in a borehole (e.g. the Hatfield blow-out near Doncaster, UK; Ward et al., 2003). Pollution incident data were reviewed for all incidents reported within 1 km of wells in England between 2001 and 2013 (the only time period for which data are available). These data were filtered for those indicating a release of crude oil to the environment. These incidents were described as pipe failures above or below ground and could be related to the well or pipelines connected to the wells. To act as a control to this data, pollution incidents within a 5 km radius of the well were also examined to assess whether there was a broader issue of hydrocarbon pollution incidents that should be considered and taken into account.

The number of wells active prior to the period covered by the pollution records was also calculated. Based on data provided by DECC, 143 onshore oil and gas wells were producing at the start of the year 2000. Between 2000 and 2013, the Environment Agency records nine pollution incidents involving the release of crude oil within 1 km of an oil or gas well (Table 7, Fig. 8). The records are not clear as to whether the incidents were due to well integrity failure, problems with pipework linked to the well, or other non-well related issues. In February 2014, therefore, the present-day operators of the wells at which the nine events occurred were contacted (Perenco, IGas, and Humbly Grove Energy Ltd.). The two pollution incidents at the Singleton Oil Field (now operated by IGas but operated by a different company when the incidents occurred) occurred in the early 1990s, and were caused by failure of cement

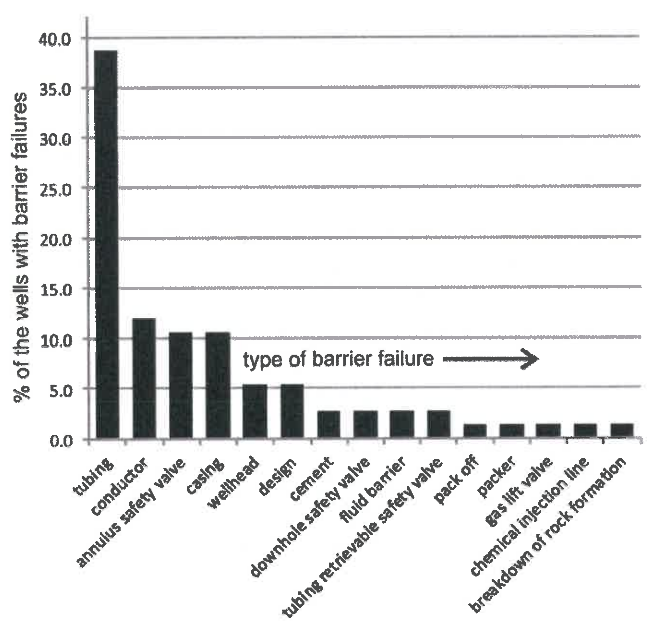


Figure 7. Causes of barrier failures for the 75 (of 406) production and injection wells surveyed in offshore Norway that showed evidence for such failures (from Vignes, 2011).

Table 2
Sources of data reporting well barrier and well integrity failures.

Country	Region	Well location	Status	Completion date	Well type	Well numbers	Failure statistics	Organisation
USA	PA	X	X	X	X	X	X	Department of Environmental Protection
	Texas	X	X	X	X	X		RRC
	Alabama	X	X	X	X	X		Geological Survey of Alabama
	New York	X	X	X	X	X		New York Department of Environmental Conservation
	Florida	X	X	X	X	X		Florida Department of Environmental Protection
	North Dakota	X	X	X	X	X	X	North Dakota Oil and Gas Division & North Dakota Department of Environmental Health
	W. Virginia	X	X	X	X	X	X	West Viginia Department of Environmental Protection
UK	National	X		X	X	X		DECC
Canada	Alberta	X	X	X	X	X	X	Energy Resources Conservation Board (ERCB)
Australia	National	X	X	X	X	X		Geoscience Australia
France	National	X	X	X	X			BRGM
Netherlands	National	X	X	X	X	X		Geological Survey of the Netherlands
Brazil	National	X		X	X	X		BDEP
Norway (offshore)	National		X	X		X		Norway Offshore Continental Shelf Data Access Portal
Poland	National	X		X	X	X		Polish Geological Institute

behind the conductor and the 9 5/8-inch casing. This was identified as a result of five groundwater monitoring boreholes installed at the Singleton Oil Field in 1993. The leak was from the well cellar (cement lined cavity in which the well head sits) via the pre-installed conductor and the 9 5/8-inch casing, both of which appear not to have been adequately cemented in-situ in at least one well. A thorough investigation commenced in 1997, including the drilling of a number (>11) of additional boreholes, and the carrying out of tracer tests and CCTV examination under the auspices of, and in consultation with, the UK Environment Agency. The leak paths, once identified and verified, were remediated. Monitoring has continued since that time and the observed pollution levels have remained below those set by the Environment Agency as requiring further action.

The other seven pollution incidents recorded by the Environment Agency between 2000 and 2013 were not caused by well integrity failure, but due to leaks from pipework linked to the well. No incidents were reported at the other well sites in the UK that were inactive or abandoned.

For context, it should be noted that there are natural, high permeability geological pathways for the migration of buoyant fluids, which are typically associated with structural features such as faults and folds (Selley, 1992). Gas and oil are naturally mobile in the UK subsurface: around 200 natural hydrocarbon seeps, mainly of oil, are known from the onshore UK and some have been used to initiate localised exploitation (Selley, 1992, 2012). A small number of natural gas seeps from shales were recorded by Selley (2012), with notable occurrences in the Weald Basin of south-east England (Selley, 2012, Fig. 5).

4.6. Summary of well barrier and integrity failure

For the countries listed (Table 1), publicly available data were tabulated on well type, well location, completion date, well status, number of wells drilled and whether well barriers and integrity failures had occurred (Table 2). Tabulation of all published and online data on well barrier and integrity failure (Table 3, Fig. 9) shows substantial variability in the number of wells that have experienced both categories of failure. This probably relates to the fact that the sizes of the datasets are variable; the included wells were drilled over a period of more than a century, using different well designs and technology; were targeting unconventional and conventional hydrocarbons; and were drilled in diverse geological settings. The most recent dataset from the Marcellus Shale (Pennsylvania, USA), which includes several thousand wells, has some of the lowest well barrier and failure rates (Fig. 9). In Table 3 we have been careful to provide the exact wording from the published source as to the nature of the failure, and to discriminate between well barrier and well integrity failures.

5. Orphaned, abandoned or idle wells

5.1. Definitions

The terms 'abandoned', 'idle' and 'orphaned' are used to describe the state of a well that did not locate economic hydrocarbons or a well at the end of its production lifecycle. The USA has the most established and comprehensive definitions of such terms, although their meaning can vary at state and federal levels.

A review of the various state regulatory practices regarding idle wells in the USA was conducted by Thomas (2001) and defined idle wells as those not currently being used for production or injection, but which have not yet been plugged and abandoned. In California, Hesson and Glinzak (2000) and Evans et al. (2003) defined idle wells as those that have been non-producing and non-injecting for six consecutive months.

In the USA, the definition of an orphaned well depends largely on the state regulatory body. Thomas (2001) defined orphaned wells as those in which the operator has gone out of business or is insolvent, such that the company that operated the well is no longer responsible for it. Based on Californian practices, Hesson (2013) defined orphaned wells as those where the operator is defunct, or where the state regulatory body has determined, based on certain criteria, that a well is orphaned. Such criteria include a well having been idle for 25 years or more, without being in compliance with idle well requirements. In Texas, the oil and gas regulatory body – the RRC – defines orphaned wells as those which have, without permit, been inactive for a year or more. In Pennsylvania, a 1992 amendment to the 1984 Oil and Gas Act defined an orphaned well as one which was abandoned prior to April 1985, which has not been operated by the present owner, and for which the present owner has received no economic benefit. For the UK data in this study, we follow the definition of Thomas (2001) and use 'orphaned' to describe wells where the operator is no longer solvent.

6. USA

Thirty-two US states have reported data on orphaned oil and gas wells (IOGCC, 2013). Fifteen of these states account for around 320,000 orphaned wells in total, with ~53,000 of these wells targeted for plugging (Table 4). The states vary greatly in how they

Table 3
Compilation of published statistics on well barrier and well integrity failure, including information on well age, number of wells included in study, well location, and terminology used to describe nature of well barrier or integrity failures.

Country	Location	No. Wells studied	% Wells with barrier failure or well integrity failure	Additional information	Published source
USA	ONSHORE Operational wells in the Santa Fe Springs Oilfield (discovered ~1921), California, USA	>50	75	Well Integrity failures. Leakage based on the 'observation of gas bubbles seeping to the surface along well casing'.	Chillingar and Endres (2005)
USA	ONSHORE Ann Mag Field, South Texas, USA (wells drilled 1998–2011)	18	61	Wells drilled 1998–2011. Well barrier failures mainly in shale zones.	Yuan et al. (2013)
USA	OFFSHORE Gulf of Mexico (wells drilled ~1973–2003)	15,500	43	Wells drilled ~1973–2003. Barrier failure. 26.2% in surface casing.	Brufato et al. (2003)
Offshore Norway	OFFSHORE Norway, 8 Companies, Abandoned Wells (wells drilled 1970–2011)	193	38	Wells drilled 1970–2011. Well integrity and barrier failure. 2 wells with likely leak to surface.	Vignes (2011)
China	ONSHORE Kenxi Resevoir, China (dates unknown)	160	31.3	Well barrier failure	Peng et al. (2007)
China	ONSHORE Gudao Resevoir, China (wells drilled 1978–1999)	3461	30.4	Wells drilled 1978–1999. Barrier failure in oil-bearing layer.	Peng et al. (2007)
Offshore Norway	OFFSHORE Norway, 8 Fields (dates unknown)	217	25	Wells monitored 1998–2007. Well integrity and barrier failure. 32% leaks occurred at well head.	Randhol and Carlsen (2007)
Canada	ONSHORE Saskatchewan, Canada (dates unknown)	435	22	Wells monitored 1987–1993. Well integrity failure: SCVF and GM	Erno and Schmitz (1996)
Offshore Norway	OFFSHORE Internal Audit, Location Unknown (dates unknown)	711	20	Barrier failure	Nilsen (2007)
Offshore Norway	OFFSHORE Norway, 12 Offshore Facilities (wells drilled 1977–2006)	406	18	Wells drilled 1977–2006. Well integrity and barrier failure. 1% had well head failure.	Vignes and Aadnøy (2010)
China	ONSHORE Daqing Field, China (wells drilled ~1980–1999)	6860	16.3	Wells drilled ~1980–1999. Barrier failure	Zhongxiao et al. (2000)
Bahrain	ONSHORE Bahrain (wells drilled 1932–2004)	750	13.1	Wells drilled 1932–2004. Failure of surface casing with some leaks to surface	Sivakumar and Janahi (2004)
Netherlands	ONSHORE Netherlands (dates unknown)	31	13	Barrier failure	Vignes (2011)
UK	OFFSHORE UK Continental Shelf (dates unknown)	6137	10	Well integrity and barrier failure.	Burton (2005)
USA	ONSHORE Marcellus Shale, Pennsylvania, USA (wells drilled 1958–2013)	8030	6.26	Well reports 2005–2013. Well integrity and barrier failure. 1.27% leak to surface.	This study
China	ONSHORE Gunan Reservoir, China (dates unknown)	132	6.1	Barrier failure	Peng et al. (2007)
USA	ONSHORE Nationwide Gas Storage Facilities (<1965–1988)	6953	6.1	Wells drilled <1965–1988. Well integrity and barrier failure.	Marlow, 1989
China	ONSHORE Hetan Reservoir, China (dates unknown)	128	5.5	Barrier failure	Peng et al. (2007)
USA	ONSHORE Marcellus Shale, Pennsylvania, USA (wells drilled 2010–2012)	4602	4.8	Wells drilled 2010–2012. Well barrier and integrity failure.	Ingraffea (2012)
Canada	ONSHORE Alberta, Canada (wells drilled 1910–2004)	316,439	4.6	Wells drilled 1910–2004. Monitored 1970–2004. Well integrity failure: SCVF and GM	Watson and Bachu (2009)
Indonesia	ON/OFFSHORE Malacca Strait (wells drilled ~1980–2004)	164	4.3	Wells drilled ~1980–2010. Both well integrity and barrier failures. Further 41.4% of wells identified as high risk of failure.	Calosa and Sadarta (2010)
USA	ONSHORE Pennsylvania, USA (wells drilled 2008–2013)	6466	3.4	Wells drilled 2005–2012. Well integrity and barrier issues. Leak to surface in 0.24% wells.	Vidic et al. (2013)
China	ONSHORE Kenli Resevoir, China (dates unknown)	173	2.9	Barrier failure	Peng et al. (2007)
USA	ONSHORE Marcellus Shale, Pennsylvania, USA (wells drilled 2008–2011)	3533	2.58	Wells drilled 2008–2011. Well integrity and barrier failure	Considine et al. (2013)
USA	ONSHORE Nationwide CCS/Natural Gas Storage Facilities (dates unknown)	470	1.9	Well integrity failure. Described as significant gas loss.	IPCC (2005)

treat wells for which they have no data. Two decades ago, the US EPA estimated that there were at least 1.2 million abandoned oil and gas wells in the United States (EPA, 1987); more than 200,000 of these wells appear to be unplugged (EPA, 1987).

As the first state to produce oil commercially in the USA, Pennsylvania illustrates the difficulty in characterizing abandoned and orphaned wells. The state has seen around 325,000 to 400,000 oil and gas wells drilled since 1859. As of 2010, the Pennsylvania Department of Environmental Protection (DEP) reported 8823 oil and gas wells targeted for plugging (IOGCC 2013). The PA DEP also reported more than 100,000 orphaned wells, but the precise location and depth of most of these was unidentified. The number of orphaned wells in Pennsylvania is probably closer to 180,000, being the difference between the conservative estimate of ~325,000 wells drilled in the state and the ~140,000 wells listed in the PA DEP database. These wells are mostly a legacy of the first 75–100 years of oil and gas drilling, before record keeping was commonplace. In fact, the earliest regulations on well plugging were designed to stop water entering hydrocarbon wells, particularly during floods, rather than to isolate oil and gas from the environment.

Lost wells represent a different classification to abandoned or orphaned wells. States in the USA report that somewhere between 828,000 and 1,060,000 oil and gas wells were drilled prior to a formal regulatory system, most of which have no information available in state databases (IOGCC, 2008). A New York state report in 1994 estimated that, of the 61,000 oil and gas wells drilled to that date, no records existed for 30,000 of them; Bishop (2013) referred to these as 'forgotten' rather than abandoned or orphaned wells.

The growing number of unplugged wells in New York State illustrates the difficulty of keeping remediation levels commensurate with the number of wells being drilled and abandoned (Bishop, 2013). Up to 2010, a total of ~75,000 oil and gas wells had been drilled in the state. Eleven thousand wells were still active at that time, leaving 64,000 'abandoned' wells (after Bishop, 2013). Of these, 15,900 had been plugged but 48,000 remained unplugged; thus only 25% of the abandoned wells in 2010 had been plugged, down from 27% in 1994. More importantly, the number of unplugged wells had grown by 13,000 since 1994, when 35,000 such wells existed (Bishop, 2013). This demonstrates that, in at least some regions, the plugging of abandoned wells is not keeping pace with the rate at which wells are being abandoned.

Some states have aggressive programmes for plugging abandoned oil and gas wells. Texas has one of the most ambitious, having plugged 41,000 wells between 1991 and 2009 at a cost of ~$80 million (IOGCC, 2008). Overall, US states spent ~$319 million in recent decades to plug and remediate ~72,000 oil and gas wells, at an average cost of ~$4500 per well. Based on that unit cost, plugging 150,000 more wells would require $668 million, and plugging all 320,000 wells estimated in Table 4 would cost $1.43 billion. In 2009, the combined balance available in all US state funds for plugging wells was ~$2.8 million, many orders of magnitude less than that required to finish the job (IOGCC, 2008).

7. UK

In the UK a total of 2152 hydrocarbon wells were drilled onshore between 1902 and 2013, with a peak in drilling activity during World War II (Fig. 10). Approximately 1000 were drilled by companies that still exist. Approximately 1050 were drilled by companies that were subject to takeovers or mergers. For example, 543 wells were drilled by the D'Arcy company, mainly between 1941 and 1961 and D'Arcy is no longer operating.

We estimate that between 50 and 100 of the 2152 wells were drilled by companies that no longer exist and were not bought or merged. In the USA such wells are termed orphaned wells. Where the company that drilled the well no longer exists, or has been taken over or merged (up to 53% of UK wells), liability for any well integrity failures that lead to pollution is unclear; in some cases it may be that of the landowner. Even if a chain of ownership through acquisition of prior licensees can be identified, the position is likely to be more complex as the legal mechanism used for the acquisition may not be known. In some instances, it is possible that a company was purchased for its assets and the liabilities were left with the original entity.

As a case study, one of the 2152 wells listed by DECC was examined (Fig. 11). Drilled in Sunderland in 2002, the well targeted coal mine gas. In February 2014 the company that drilled the well was contacted to confirm the status of the well as either abandoned or temporarily abandoned (suspended). No gas had been produced due to elevated water levels and the well was temporarily abandoned (suspended) in 2002, pending transfer of ownership to the Coal Authority, for water level monitoring or abandonment. The surrounding land has since been acquired by developers and is currently (February 2014) the site of a new residential housing estate. As of February 2014, the well is now being abandoned (DECC, pers. comm.).

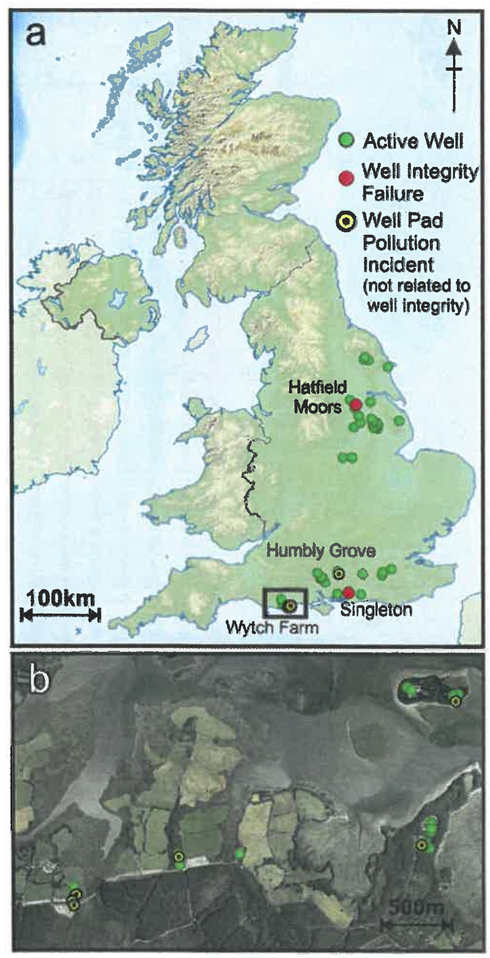


Figure 8. (a) UK map showing locations of wells active in 1999 and crude oil discharges (b) Coincidence of pollution reports with well pads in the Wytch Farm area, southern England.

Many wells have been drilled in areas where there are highly productive aquifers (Fig. 12a) and there is a good spatial correspondence between potential shale reservoirs and highly productive aquifers (Fig. 12b). In the USA, many shale gas wells have also been drilled where there are active aquifers (King and King, 2013).

7.1. Surface identification of wells in the UK

A surface identification study of the 2152 UK onshore hydrocarbon wells was carried out. 128 wells were not included because: (a) the wells were younger than the available satellite imagery and so could not be located using this method (114 wells); (b) the wells were listed in the onshore well database (DECC, 2013) but were not present on the UKOGL map (5 wells); or (c) the wells were listed as 'offshore' in the DECC onshore well database (9 wells).

The remaining 2024 wells were categorised as follows:

a. Cleared area of land present, consistent with site being used as well pad; machinery present and site apparently in use;
b. Indications that well had once been present on site, but clearly not active.
c. No well pad or machinery visible; no indication that well had ever been present on site;

Of the well sites included in our study (Table 5), 33.7% were clearly visible (i.e. the well pad and associated equipment could be

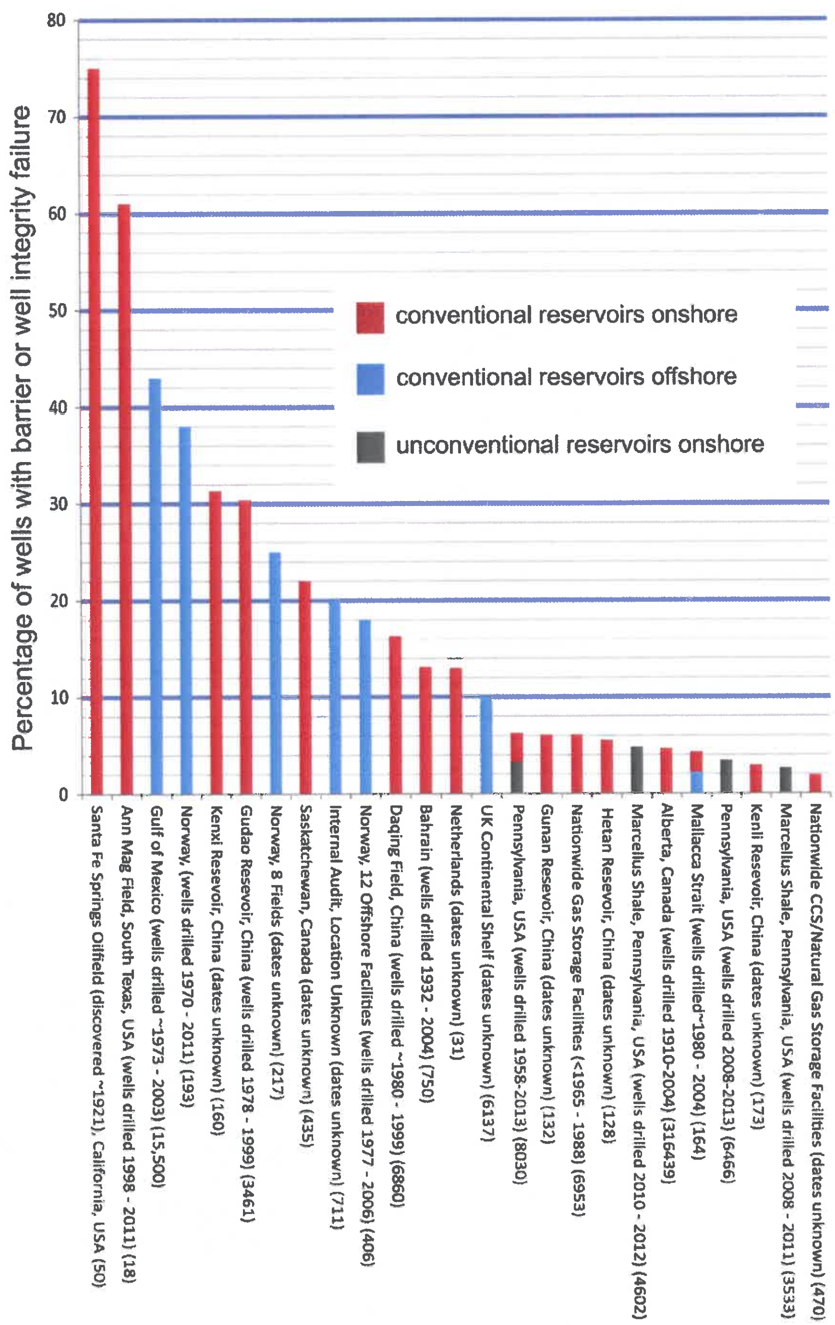


Figure 9. Graph of percentage of well barrier and integrity failures reported in 25 different studies around the world, with drilling dates and number of wells in each study.

Table 4
Estimated numbers of orphaned oil and gas wells for each U.S. state reporting at least 1000 orphaned wells (IOGCC, 2008). Thirty-two of 50 states reported data on orphaned wells.

State	Orphaned oil or gas wells	Orphaned wells targeted by state for plugging
Pennsylvania	180,000	8823
New York	44,600	4600
Kansas	30,000	6500
Kentucky	14,880	12,800
Oklahoma	12,000	1685
Ohio	9500	524
Texas	7323	7323
Tennessee	4053	53
West Virginia	3999	1385
Illinois	3766	3766
Indiana	3000	756
Louisiana	2793	2793
Missouri	2000	2000
South Dakota	1288	NA
California	1000	181
Total	320,202	53,189

seen; Fig. 13a), 5.5% showed evidence of prior on-site drilling activity without the current presence of drilling production, drilling equipment or a well head (Fig. 13b), and 65.2% were not visible (Fig. 13c). For 1.1% of sites it was unclear as to whether a well pad existed. These sites mainly comprise industrial locations where it could not be determined visually whether the infrastructure present was related to a well site. It is likely that the reason that 65.2% of wells are not visible is that UK regulations state that, after abandonment, the well should be sealed and cut and the land reclaimed.

8. Discussion

To provide context for the statistics on well barrier failure reviewed above, comparative data are reported from other industrial processes, primarily mining in the UK and geothermal energy abstraction. The number of wells that may be required to produce shale gas is also considered.

8.1. Coal mining

There are estimated to be ~250,000 lost mining shafts in the UK (Chambers et al., 2007) and many coal exploration boreholes. During mine operation, the potential for cross-contamination between mined coal horizons and overlying potable aquifers is relatively low due to the fact that mine workings are dewatered (often at a regional scale, comprising several interconnected pits) to facilitate access by the workforce. However, following mine abandonment and the cessation of dewatering, groundwater rebound occurs over 10–20 years and has the potential to contaminate overlying aquifers. This process is driven by the hydraulic head in the coal workings exceeding that of the overlying aquifer (Younger et al., 2002). In northern England, cessation of pumping for mine dewatering in part of the Durham Coalfield led to pollution of the overlying Magnesian Limestone aquifer, used for public water supply. As a consequence, this led to the aquifer failing an EU Water Framework Directive (WFD) environmental objective for groundwater quality (Neymeyer et al., 2007). More broadly, the 2009 River Basin Management Plans, required as part of the implementation of the EU WFD, reported that 34 out of 304 groundwater bodies in England and Wales had failed 'good' status environmental objectives due to groundwater pollution by rising waters following mine abandonment (including coal and metal mines). In some areas, abandoned mine workings also liberate methane, and emissions from abandoned UK coal mines were estimated to be ~14 million m^3 of methane in 2008 (UNFCCC, 2010).

8.2. Geothermal energy

Environmental concerns linked to the exploitation of geothermal energy include the mobilisation of contaminants from the surrounding rock that could lead to the contamination of aquifers by geothermal fluids. In the Balcova Geothermal Field in Turkey, there has been thermal and chemical contamination of the overlying aquifer by elements such as arsenic, antimony and boron. Aksoy et al. (2009) recommended that regular inspection and maintenance of geothermal wells should be carried out.

Summers et al. (1980) characterised geothermal fluids and investigated the possible sources of well barrier and integrity failure and the potential for contamination. Based on their analysis, they proposed a methodological framework for identifying groundwater contamination from geothermal energy developments. Possible sources of well barrier and integrity failure of geothermal wells include loading from the surrounding rock formation, mechanical damage during well development, corrosion and scaling from geothermal fluids, thermal stress, metal fatigue and failure, and expansion of entrapped fluids (Southon, 2005).

The mixing of deep geothermal fluids with shallow groundwaters can occur via natural mechanisms, such as natural upward fluid convection along fault lines (e.g. within the Larderello geothermal field, Italy; Bellani et al., 2004), and by anthropogenic activities, including uncontrolled discharges to surface waters, faulty injection procedures (e.g. Los Azufres, Mexico: Birkle and Merkel, 2000), and accelerated upward seepage from failed casings within wells and boreholes. Casing failures related to inconsistencies in casing cementation have been cited as one common cause of failure (Snyder, 1979). The major failures of several geothermal wells on

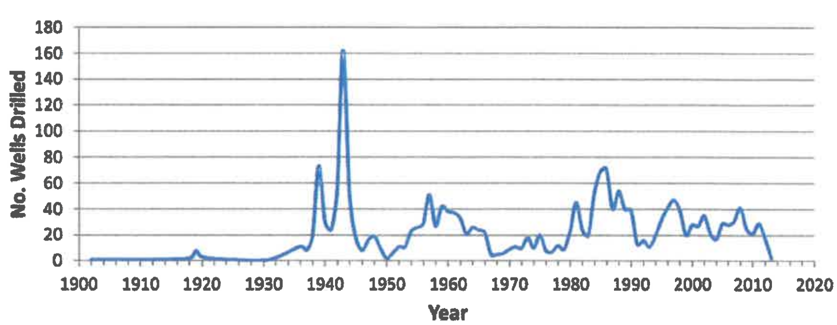


Figure 10. Graph showing number of hydrocarbon wells drilled in UK per year.

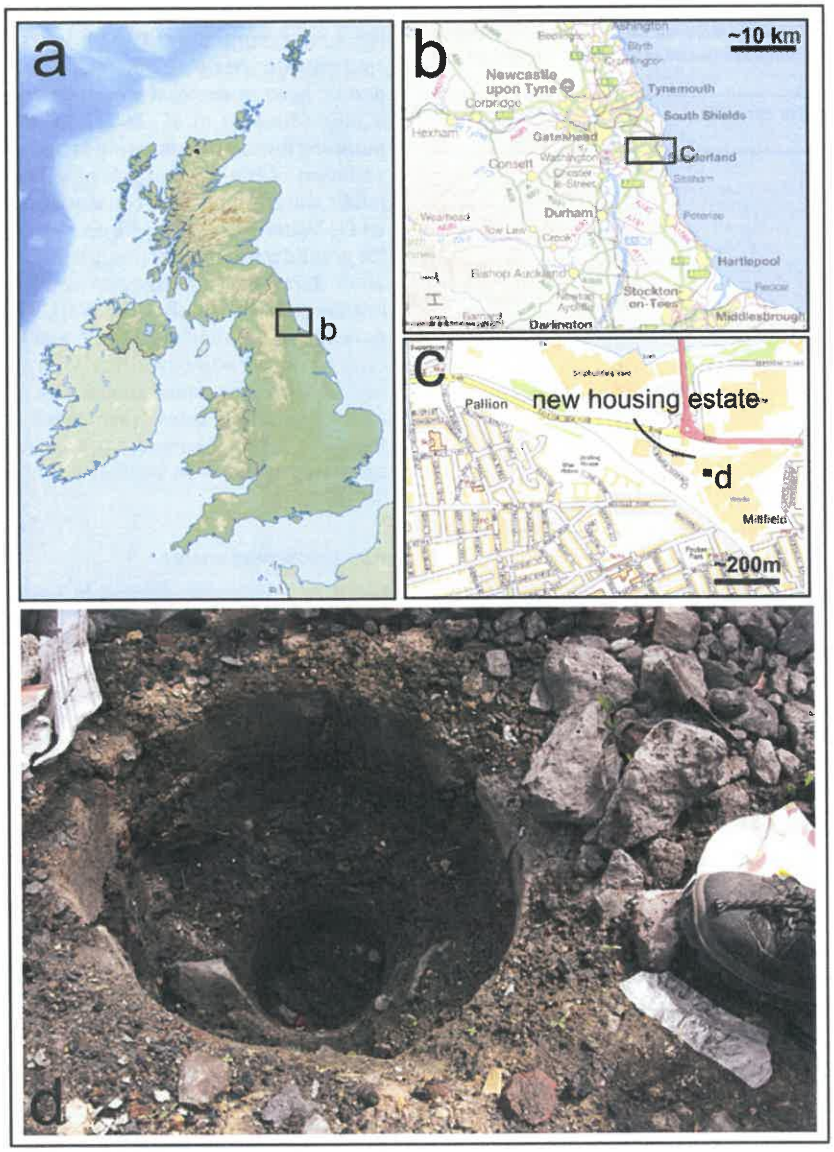


Figure 11. Case study of gas exploration well abandonment in Sunderland, UK: (a) Map of the UK; (b) location of Sunderland; (c) location of new housing estate; (d) photograph of temporarily abandoned (suspended) mine gas exploration borehole on building site of new housing estate (Grid Ref. 438260 557420). Well was completed in 2002 to a depth of 465 m.

the island of Milos, Greece, were attributed to thermal stresses on the well casing that were exacerbated by poor cementation (Chiotis and Vrellis, 1995). There is little published literature on failure rates of geothermal wells, and failure rates are expected to vary due to the wide range of geological settings from which geothermal energy can be exploited, with volcanically active regions carrying higher levels of risk than more tectonically quiescent regions.

8.3. Number of wells for shale gas exploitation

The number of wells that could be drilled to exploit shale gas in Europe depends on various factors, including geological conditions, social acceptance and economics. Based on data from shale gas plays in the USA, the estimated ultimate recovery (EUR) of a shale gas well varies from 1.4 BCF (0.0392 BCM) to 5.9 BCF (0.165 BCM) (Table 6; Baihly et al., 2010). If similar recoveries are assumed for wells in European shale plays, between 169 and 714 wells would be required for every 1 TCF (0.028 TCM) of total production. In comparison, it has been calculated (Gluyas et al., unpublished data) that conventional gas wells in the Rotliegend, which is a gas-bearing sandstone reservoir in the Southern North Sea, have EURs of between 1 and 100 times more gas per well.

8.4. Shale exploitation and water contamination

As shale reservoirs have very low permeability compared to conventional sandstone or carbonate reservoirs (typically between 3.9×10^{-6} and 9.63×10^{-4} mD: Yang and Aplin, 2007), fluid movement through and from shales is likely to be extremely slow. Therefore the potential for shales at depth to be the source of pollutants in the near-surface environment under natural conditions is low. Geological timescales would be required for significant quantities of hydrocarbons to migrate from a shale reservoir that has not been artificially hydraulically fractured.

The drilling of wells to access gas-bearing shales requires the penetration of geological formations close to the surface that will

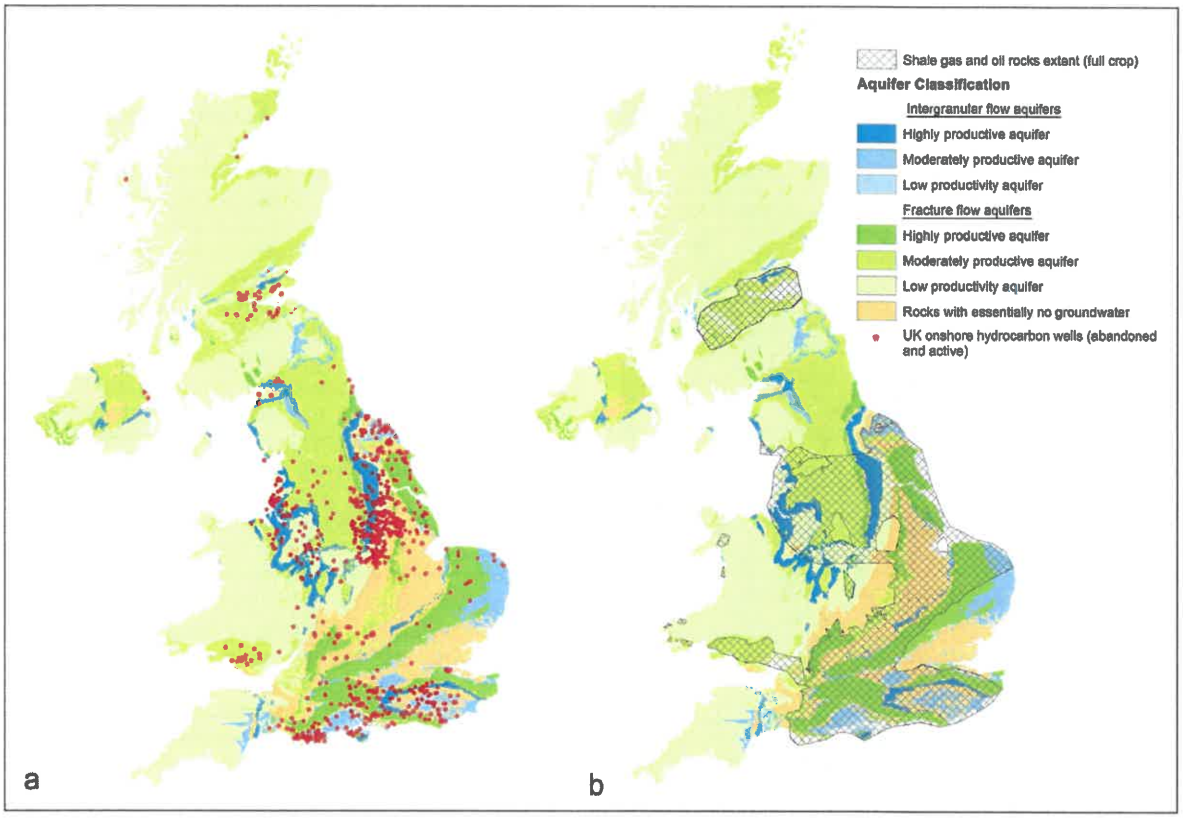


Figure 12. (a) Map of UK showing location of onshore wells drilled for exploration or production and productive aquifers. (b) Map of UK showing location of potential shale gas and oil reservoirs and productive aquifers. Aquifer base map reproduced with the permission of the British Geological Survey. ©NERC. All rights Reserved.

often contain freshwater. Where there is sufficient permeability and storage capacity, these formations will form aquifers (Fig. 12) that may be exploited for drinking water or industrial uses, such as agriculture. Even where aquifers are not currently utilised, they have the potential to be, and therefore require protection. Consideration also needs to be given to protecting groundwater that supports base flow to rivers and wetland ecosystems. Protection is achieved through preventing hazardous pollutants or limiting non-hazardous pollutants entering groundwater (European Commission, 2000). Of the 2152 hydrocarbon wells drilled in the UK, the well heads of 428 (20%) of these are located above highly productive aquifers (likely to be exploited for public water supply) and a further 535 (25%) are above moderately productive aquifers, likely to be exploited for both public and private drinking water supplies (Fig. 12a).

Table 5
Statistics on visibility and accessibility of UK onshore wells.

	Number of wells (out of total of 2024 included in study)	Percentage
Visible	682	33.70
Not visible	1319	65.17
Unclear	23	1.14
	Number of Wells on Visible Sites	Percentage
On active sites	626	30.93
Non-active/former/derelict sites	112	5.53
Urban	159	7.86
Urban/built over	182	8.99

Evidence from conventional hydrocarbon fields shows that hydraulic fracturing due to the injection of fluids can, in very exceptional circumstances, lead to fracture propagation to the surface or near-surface, if it takes place at relatively shallow depths. In the Tordis Field of offshore Norway, for example, the average rate of water injection was 7000 m^3 day^{-1} for 5.5 months (total volume = ~1,115,000 m^3). Hydraulic fractures propagated from a depth of ~900 m to the surface through Cenozoic (Tertiary) strata. The volume of fluid used in these operations, however, was more than 120 times greater than that typically used for hydraulic fracture stages in shale gas reservoirs and took place over a time period hundreds of times longer. There are several factors in shale fracking operations, including the relatively low volumes of fluid and the short pumping times that make the upward propagation of very tall fractures unlikely (Davies et al., 2012). To date, water contamination caused directly by the upward propagation of hydraulic fractures remains unproven (Davies, 2011), although the possibility cannot be totally ruled out.

As argued by Davies (2011) and Jackson et al. (2013), poor well integrity is a far more likely cause of elevated concentrations of thermogenic methane in shallow groundwater and water supplies than pathways induced solely by hydraulic fracturing. Examples of leaks in shale gas wells have been reported and fines imposed (Roberts, 2010).

8.5. Implications and recommendations

As with our study, King and King (2013) addressed statistics on well barrier and integrity failure. They compared the data with that of other polluting activities in the USA, such as storage tanks, septic

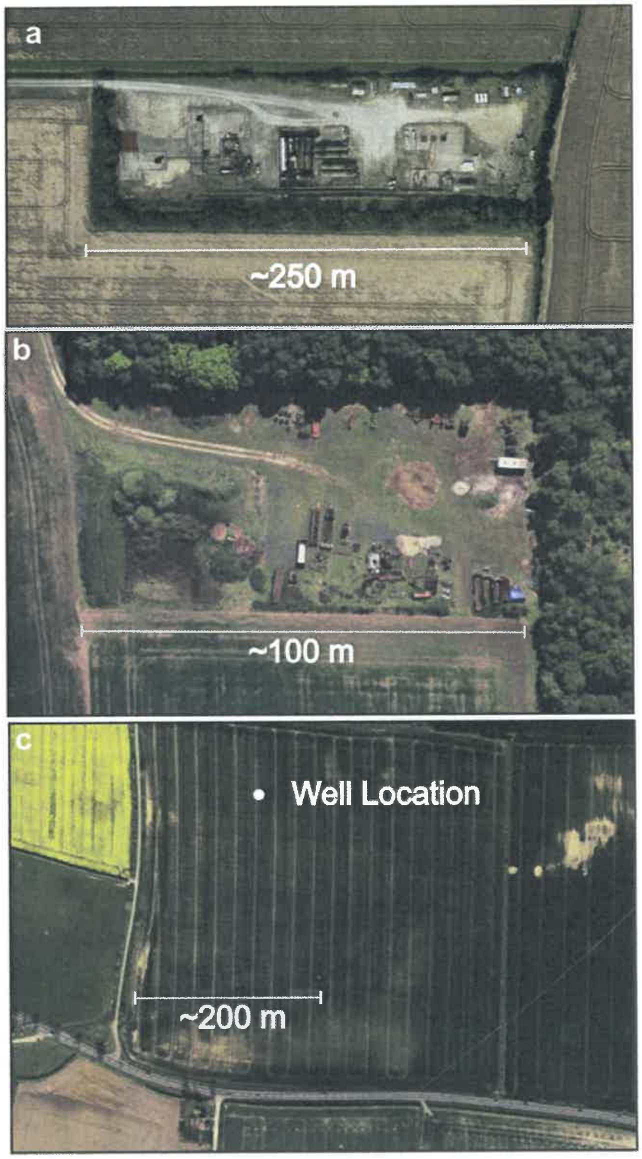


Figure 13. Examples of wells locations taken from UKOGL imaged with Google Earth, illustrating range of surface manifestations of UK onshore wells: (a) cleared area of land with appearance of being a maintained well pad; (b) cleared area of land with appearance of poorly maintained and potentially disused well pad. (c) Location of well drilling in which no well pad or machinery is visible.

tanks and landfills, and made the point that the number of reports of pollution from oil and gas wells was insignificant in comparison. Nevertheless, for the more than 4 million wells drilled in Australia, Austria, Bahrain, Brazil, Canada, Netherlands, Poland, UK and USA alone, there is scarce published or online data on well integrity or barrier failure. Improved monitoring is crucial for a better understanding of chances of hydrocarbon well barrier and integrity failure and the impact of this. There are examples of good practice. The DEP database for Pennsylvania, USA, was used by Considine et al. (2013) to carry out a detailed breakdown of the types of well infringements and their severity. The Alberta Energy Resources Board (ERCB) database of well integrity failure for 316,439 wells reported by industry dating back to 1910 is not in the public domain, but the data summary is available (Watson and Bachu, 2009). In Alberta wells are checked for well integrity and barrier failure within 60 days of the drill rig being removed (Watson and Bachu, 2009).

Table 6
Estimated Ultimate Recovery (EUR) for 5 shale gas provinces in the USA (from Baihly et al., 2010).

Shale play	EUR after 30 years (BCF-0.028 BCM)
Barnett	3.0
Fayetteville	1.4
Woodford	1.7
Haynesville	5.9
Eagle Ford	3.8

In the UK there have been a small number of reported pollution incidents associated with active wells and none with inactive abandoned wells. This could therefore indicate that pollution is not a common event, but one should bear in mind that monitoring of abandoned wells does not take place in the UK (or any other jurisdiction that we know of) and less visible pollutants such as methane leaks are unlikely to be reported. It is possible that well integrity failure may be more widespread than the presently limited data show. Surveying the soils above abandoned well sites would help establish if this is the case. In terms of monitoring, abandoned wells could be checked 2–3 months after cement plugging for sustained casing pressure and gas migration. If the well has no evidence for barrier or integrity failure, it could be cut and buried as per regulations. Soils above well sites could be monitored every 5 years for emissions that are above a pre-determined statutory level. As there are 2152 wells in UK at present, only 430 would need to be checked each year. Monitoring could be intensified or scaled down based upon the results of the first complete survey. Monitoring a proportion of future abandoned shale gas and oil wells should also be feasible. A mechanism may need to be established in the UK and/or Europe to fund repairs on orphaned wells, and an ownership or liability survey of existing wells would be timely.

9. Conclusions

Well barrier and integrity failure is a reasonably well-documented problem for conventional hydrocarbon extraction and the data we report show that it is an important issue for unconventional gas wells as well. It is apparent, however, that few data exist in the public domain for the failure rates of onshore wells in Europe. It is also unclear which of the datasets used in this study will be the most appropriate analogues for well barrier and integrity failure rates at shale gas production sites in the UK and Europe. Only 2 wells in the UK have recorded well integrity failure (Hatfield Blowout and Singleton Oil Field) but this figure is based only on data that were publicly available or accessible through UK Environment Agency and only out of the minority of UK wells which were active. To the best of our knowledge and in line with other jurisdictions (e.g. Alberta, Canada) abandoned wells in the UK are sealed with cement, cut below the surface and buried, but are not subsequently monitored. This number is therefore likely to be an underestimate of the actual number of wells that have experienced integrity failure. A much tighter constraint on the risks and impacts would be obtainable if systematic, long-term monitoring data for both active and abandoned well sites were in the public domain. It is likely that well barrier failure will occur in a small number of wells and this could in some instances lead to some form of environmental contamination. Furthermore, it is likely that, in the future, some wells in the UK and Europe will become orphaned. It is important therefore that the appropriate financial and monitoring processes are in place, particularly after well abandonment, so that legacy issues associated with the drilling of wells for shale gas and oil are minimised.

Table 7
Crude oil pollution incidents within 1 km of 143 well pads active in UK at start of year 2000.

Event no.	Date reported	Lat.	Lon.	Cause	Due to well integrity failure (Y/N)	Environmental impact		
						Air	Land	Water
981998	18/04/2012	51.19415	−1.009848	Pipe Failure above ground	N	No Impact	Minor	No Impact
639443	08/12/2008	50.93129	−0.74344026	Other	Y	No Impact	No Impact	Minor
685648	08/06/2009	50.92439	−0.73782083	Other	Y	No Impact	No Impact	Minor
137932	19/02/2003	50.66674	−2.0292232	Accidental spillage	N	No Impact	No Impact	No Impact
838199	14/11/2010	50.66655	−2.0290391	Pipe failure below ground	N	Minor	Minor	No Impact
157014	09/05/2003	50.66737	−2.0287566	Control system failure	N	No Impact	No Impact	Minor
138317	21/02/2003	50.67028	−2.0162917	Pipe failure above ground	N	No Impact	No Impact	No Impact
428461	18/08/2006	50.67125	−1.9866881	Pipe failure above ground	N	No Impact	No Impact	No Impact
8177	07/06/2001	50.68239	−1.9825378	Pipe failure below ground	N	No Impact	Minor	Minor

Acknowledgements

We thank Chris Green (GFrac Technologies) and an anonymous reviewer for their reviews which helped improve the paper. Dr Paul Choate (Choate Technology Services Ltd.) and Dr Will Fleckenstein (Colorado School of Mines) are also thanked for reading and commenting on the manuscript. This research was carried out as part of the ReFINE (Researching Fracking in Europe) consortium led by Durham University and funded by the Natural Environment Research Council (UK), Total, Shell and Chevron. We thank Alkane Energy, BP, Chevron, Department of Energy and Climate Change, Humbly Grove Energy Ltd., IGas, Perenco, Shell, Total for comments. The US National Science Foundation (EAR-#1249255) funded some of the US analyses and the Environment Agency (UK) is thanked for providing pollution incident data. We are grateful to the Durham University Faculty of Science Ethics Committee and the UK Research Integrity Office for their time in providing advice on research ethics. We thank the ReFINE Independent Science Board (http://www.refine.org.uk/how-we-work/independent-science-board) for spending time prioritising the research projects undertaken by ReFINE. This paper is published with the permission of the Executive Director of the British Geological Survey and the results and conclusions are solely those of the authors.

References

Aksoy, N., Şimşek, C., Gunduz, O., 2009. Groundwater contamination mechanism in a geothermal field: a case study of Balcova, Turkey. J. Contam. Hydrol. 103, 13–28.
Baihly, J., Altman, R., Malpani, R., Luo, F., 2010. Shale gas production decline trend comparison over time and basins. Soc. Pet. Eng.. http://dx.doi.org/10.2118/135555-MS.
BDEP. Well Data. Retrieved 2013, from National Agency for Oil, Natural Gas and Biofuels (ANP), Brazil: http://www.bdep.gov.br/?id=191.
Beckstrom, J.A., Boyer, D.G., 1993. Aquifer-Protection considerations of coalbed methane development in the San Juan Basin. SPE Form. Eval. 8, 71–79. http://dx.doi.org/10.2118/21841-PA.
Bellani, S., Brogi, A., Lazzarotto, A., Liotta, D., Ranalli, G., 2004. Heat flow, deep temperatures and extensional structures in the Larderello Geothermal Field (Italy): constraints on geothermal fluid flow. J. Volcanol. Geotherm. Res. 132, 15–29.
Birkle, P., Merkel, B., 2000. Environmental impact by spill of geothermal fluids at the geothermal field of Los Azufres, Michoacán, Mexico. Water, Air Soil. Pollut. 124, 371–410.
Bishop, R.E., 2013. Historical analysis of oil and gas well plugging in New York: is the regulatory system working? New. Solut. 23, 103–116.
Brufatto, C., Cochran, J., Power, L.C.D., El-Zeghaty, S.Z.A.A., Fraboulet, B., Griffin, T., Munk, S., Justus, F., Levine, J., Montgomery, C., Murphy, D., Pfeiffer, J., Pornpoch, T., Rishmani, L., 2003. From mud to cement – building gas wells. Schlumb. Oil Field Rev. 15, 62–76.
Bureau de Recherches Géologiques et Minières, French National Oil and Gas Data. Accessed 2013 at: www.beph.net/html/beph_sig.htm?idp=&;f=2MST&map=&x=500000&y=2100000&r=500&langue=GB.
Calosa, W.J., Sadarta, B., 2010. Well integrity issues in Malacca Strait contract area. Soc. Pet. Eng.. http://dx.doi.org/10.2118/129083-MS.
Celia, M.A., Bachu, S., Nordbotten, J.M., Kavetski, D., Gasda, S.E., 2005. Modeling Critical Leakage Pathways in a Risk Assessment Framework: Representation of Abandoned Wells. Conference Proceedings, Fourth Annual Conference on Carbon Capture and Sequestration DOE/NETL, May 2–5.
Chambers, J.E., Wilkinson, P.B., Weller, A.L., Meldrum, P.I., Ogilvy, R.D., Caunt, S., 2007. Mineshaft imaging using surface and crosshole 3D electrical resistivity tomography: a case history from East Pennine Coalfield, UK. J. Appl. Geophys. 62 (4), 324–337.
Cheung, K., Klassen, P., Mayer, B., Goodarzi, F., Aravena, R., 2010. Major ion and isotope geochemistry of fluids and gases from coalbed methane and shallow groundwater wells in Alberta, Canada. Appl. Geochem. 25, 1307–1329.
Chillingar, G., Endres, B., 2005. Environmental hazards posed by the Los Angeles Basin urban oilfields: an historical perspective of lessons learned. Environ. Geol. 47, 302–317.
Chiotis, E., Vrellis, G., 1995. Analysis of casing failures of deep geothermal wells in Greece. Geothermics 24, 695–705.
Chivvis, R.W., Julian, J.Y., Cary, D.N., 2009. Pressure Activated Sealant Economically Repairs Casing Leaks on Prudhoe Bay Wells. SPE 120978.
Considine, T.J., Watson, R.W., Considine, N.B., Martin, J.P., 2013. Environmental regulation and compliance of Marcellus shale gas drilling. Environ. Geosci. 20, 1–16.
Crook, R., Kulakofsky, D., Griffith, J., 2003. Tailor lightweight slurry designs to well conditions and productions plans. World Oil 224 (10).
Davies, R.J., 2011. Methane contamination of drinking water caused by hydraulic fracturing remains unproven. Proc. Natl. Acad. Sci. 108, E871.
Davies, R.J., Mathias, S.A., Moss, J., Hustoft, J., Newport, L., 2012. Hydraulic fractures: how far can they go? Mar. Pet. Geol. 37, 1–6.
Davies, R.J., Foulger, G.R., Bindley, A., Styles, P., 2013. Induced seismicity and hydraulic fracturing for the recovery of hydrocarbons. Mar. Pet. Geol. 45, 171–185.
DECC, 2013. Oil and Gas: Onshore Exploration and Production. Retrieved from. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/200131/Landwells17_May2013.xlsx.
Department of Environmental Protection (DEP): Bureau of Oil and Gas Management, 2000. Pennsylvania's Plan for Addressing Problem Abandoned Wells and Orphaned Wells. DEP. 550-0800-001.
Dusseault, M., Gray, M., Nawrocki, P., 2000. Why Oilwells Leak: Cement Behavior and Long-term Consequences. SPE 64733.
EIA. Crude Oil and Natural Gas Exploratory and Development Wells. Retrieved 2012, from Energy Information Administration: http://www.eia.gov/dnav/ng/ng_enr_wellend_s1_m.htm.
Energy Resources Conservation Board, Statistical Reports. Retrieved 2013 from http://www.aer.ca/data-and-publications/statistical-reports/st37.
EPA, 1987. Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy. Office of Solid Waste and Emergency Response, Washington, D.C. http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=20012D4P.PDF.
Erno, B., Schmitz, R., 1996. Measurements of soil Gas migration around oil and Gas Wells in the Lloydminster area. J. Can. Pet. Technol. 35, 37–45.
European Commission, 2000. Directive 2000/60/EC of the European Parliament and of the Council establishing a framework for the community action in the field of water policy Directive 2000/60/EC of the European Parliament and of the Council establishing a framework for the Community action in the field of water policy. Off. J. Eur. Commun. L 327/1 - L 327/72.
Evans, B.L., Sailor, R.P., Santiago, E., 2003. Well Abandonment in the Los Angeles Basin. SPE 83443.
Florida Department of Environmental Protection, Oil and Gas Data Maps. Retrieved 2013 from http://www.dep.state.fl.us/water/mines/oil_gas/data.htm.
Geological Society of Alabama, State Oil and Gas Board Databases. Retrieved 2013 from http://www.gsa.state.al.us/ogb/db_main.html.
Geological Survey of the Netherlands. Wells. Retrieved 2013, from NL Oil and Gas Portal: http://www.nlog.nl/nlog/requestData/nlogp/allBor/queryForm?menu=act.
Geoscience Australia. (n.d.). Petroleum Wells. Retrieved 2013, from Australian Government – Geoscience Australia: http://dbforms.ga.gov.au/www/npm.well.search.
Hesson, B.H., Glinzak, M., 2000. California Division of Oil, Gas and Geothermal Resources: Idle Well Management Program. SPE 62576.

Hesson, B.H., 2013. California Department of Conservation/Division of Oil, Gas, and Geothermal Resources: Orphan Well Program. SPE 165340.

Ingraffea, A., 2012. Fluid Migration Mechanisms Due to Faulty Well Design and/or Construction: an Overview and Recent Experiences in the Pennsylvania and Marcellus Play. http://www.psehealthyenergy.org/site/view/1057.

IOGCC (Interstate Oil and Gas Compact Commission), 2013. Groundwork: Orphaned Wells Program, Oklahoma City, OK, USA (accessed October 2013). http://groundwork.iogcc.org/topics-index/orphaned-wells/state-progress.

IOGCC (Interstate Oil and Gas Compact Commission), 2008. Protecting Our Country's Resources: the States' Case. Orphaned Well Plugging Initiative, Oklahoma City, OK, USA.

IPCC, 2005. Special Report on Carbon Dioxide Capture and Storage, pp. 195–277.

IPCC, 2013. Climate Change 2013; the Physical Science Basis, 714.

Jackson, R.B., Vengosh, A., Darrah, T., Warner, N.R., Down, A., Poreda, R.J., Osborn, S.G., Zhao, K., Karr, J.D., 2013. Increased stray gas abundance in a subset of drinking water wells near Marcellus shale gas extraction. Proc. Natl. Acad. Sci. 110, 11250–11255.

Johns, J.E., Aloisio, F., Mayfield, D.R., 2011. Well Integrity Analysis in Gulf of Mexico Wells Using Passive Ultrasonic Leak Detection Method. SPE 142076.

King, G.E., King, D.E., 2013. Environmental Risk Arising from Well-construction Failure – Differences between Barried and Well Failure and Estimates of Failure Frequency across Common Well Types, Locations and Well Age. SPE 16142.

Marshall, M., Strahan, D., 2012. Total foresaw the North Sea gas leak. New. Sci. 214, 6–7.

Marlow, R., 1989. Cement Bonding Characteristics in Gas Wells. SPE 17121.

Miller, S.M., Wofsy, S.C., Michalak, A.M., Kort, E.A., Andrews, A.E., Biraud, S.C., Dlugokencky, E.J., Eluskiewicz, J., Fisher, M.L., Janssens-Maenhout, G., Miller, B.R., Miller, J.B., Montzka, S.A., Nehrkorn, T., Sweeney, C., 2013. Anthropogenic emissions of methane in the United States. Proc. Natl. Acad. Sci. 110, 20018–20022.

Miyazaki, B., 2009. Well Integrity: an Overlooked Source of Risk and Liability for Underground Natural Gas Storage. Lessons Learned from Incidents in the USA. In: Geological Society, London, Special Publications, vol. 313, pp. 163–172.

New York Department of Environmental Conservation, Oil and Gas Searchable Database. Retrieved 2013 from: http://www.dec.ny.gov/cfmx/extapps/GasOil/search/wells/index.cfm.

Neymeyer, A., Williams, R.T., Younger, P.L., 2007. Migration of polluted mine water in a public supply aquifer. Q. J. Eng. Geol. Hydrol. 40, 75–84.

Nilsen, L.H., 2007. Brønnintegritet I Statoil og på norsk sokkel. Published at the NPF 20' Kristiansand Conference [Online]. Available. http://www.npf.no/.

North Dakota Department of Health, Environmental Incident Reports. Accessed 20/2/2014 at: http://www.ndhealth.gov/ehs/spills/.

North Dakota Oil and Gas Division, Well Search. (accessed 20.02.14.) at: https://www.dmr.nd.gov/oilgas/findwellsvw.asp.

Norway Offshore Continental Shelf Data Access Portal, Public Well Statistics. Retrieved 2013 from http://www.landmarkvspace.com/nocs/wells/stats.aspx.

Osborn, S.G., Vengosh, A., Warner, N.R., Jackson, R.B., 2011. Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. Proc. Natl. Acad. Sci. 108, 8172–8176.

Peng, S., Fu, J., Zhang, J., 2007. Borehole casing failure analysis in unconsolidated formations: a case study. J. Pet. Sci. Eng. 59, 226–238.

Polish Geological Institute, Borehole Database, Accessed November 2013 from http://otworywiertnicze.pgi.gov.pl/

Randhol, P., Carlsen, I.M., 2007. Presentation Assessment of Sustained Well Integrity on the Norwegian Continental Shelf. SINTEF Petroleum Research [Online], Available: http://www.co2captureandstorage.info/docs/wellbore/Wellbore%20Presentations/4th%20Mtg/01.pdf.

RRC. Well Information. Retrieved 2013, from Rail Road Commission of Texas: http://www.rrc.state.tx.us/data/wells/index.php.

Roberts, J.S., 2010. Testimony of J. Scott Roberts, Deputy Secretary for Mineral Resources Management Department of Environmental Protection Before the House Republican Policy Committee Thursday, May 20.

Sivakumar, V.C., Janahi, I., 2004. Salvage of Casing Leak Wells on Artificial Lift in a Mature Oil Field. SPE. 88747.

Smith, D., 1976. Cementing. Millet the Printer Inc, Dallas.

Summers, K., Gherini, S., Chen, C., 1980. Methodology to Evaluate the Potential for Ground Water Contamination from Geothermal Fluid Releases, vol. 1. Industrial Environmental Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency.

Selley, R.C., 1992. Petroleum seepages and impregnations in Great Britain. Mar. Pet. Geol. 9, 225–328.

Selley, R.C., 2012. UK shale gas: the story so far. Mar. Pet. Geol. 31, 100–109.

Southon, J.N., 2005. Geothermal well design, construction and failures. In: Proceedings World Geothermal Congress, pp. 24–29.

Snyder, R., 1979. Geothermal well completions: a critical review of downhole problems and specialized technology needs. In: SPE Annual Technical Conference and Exhibition.

Thomas, K.T., 2001. Produce or Plug? a Summary of Idle and Orphan Well Statistics and Regulatory Approaches. SPE 68695.

The Royal Society and The Royal Academy of Engineering, 2012. Shale Gas Extraction in the UK: a Review of Hydraulic Fracturing. Available. http://royalsociety.org/uploadedFiles/Royal_Society_Content/policy/projects/shale-gas/2012-06-28-Shale-gas.pdf.

Torbergsen, H.E., Haga, H.B., Sangesland, S., Aadnøy, B.S., Sæby, J., Johnsen, S., Rausand, M., Lundeteigen, M.A., 2012. An Introduction to Well Integrity. NorskOlje&Gass. Available. http://www.norskoljeoggass.no/en/Publica/HSE-and-operations/Introduction-to-well-integrity/.

Traynor, J.J., Sladen, C., 1997. Seepage in Vietnam – onshore and offshore examples. Mar. Pet. Geol. 14, 345–362.

UNFCCC, 2010. Annex I party GHG inventory submissions, united nations framework convention on climate change.

United Kingdom Onshore Geophysical Library (UKOGL), Interactive Map. Accessed Sep–Oct 2013 from: http://maps.lynxinfo.co.uk/UKOGL_LIVEV2/main.html.

Van Stempvoort, D., Maathuis, H., Jaworski, E., Mayer, B., Rich, K., 2005. Oxidation of fugitive methane in ground water linked to bacterial sulphate reduction. Ground Water. 43, 187–199.

Véron, J., 2005. The Alpine Molasse Basin – review of petroleum geology and remaining potential. Bull. für Angew. Geol. 10, 75–86.

Vidic, R.D., Brantley, S.L., Vandenbossche, J.M., Yoxtheimer, D., Abad, J.D., 2013. Impact of shale Gas development on regional water quality. Science 340, 6134.

Vignes, B., Aadnøy, B.S., 2010. Well-integrity issues offshore Norway. SPE 112535.

Vignes, B., 2011. Contribution to Well Integrity and Increased Focus on Well Barriers from a Life Cycle Aspect (PhD thesis). University of Stavanger.

Ward, J., Chan, A., Ramsay, B., 2003. The Hatfield Moors and Hatfield west Gas (Storage) Fields, south Yorkshire. Geol. Soc. Lond. Memoirs 20, 903–910.

Watson, T., Bachu, S., 2009. Evaluation of the Potential for Gas and CO_2 Leakage Along Wellbores. SPE 106817.

West Virginia Department of Environmental Protection, Oil and Gas Production Data. Retrieved 2013 from http://www.dep.wv.gov/oil-and-gas/databaseinfo/Pages/default.aspx.

Xu, Y., Yang, Q., Li, Q., Chen, B., 2006. The Oil Well Casing's Anticorrosion and Control Technology of Changqing Oil Field. SPE 104445.

Yang, Y., Aplin, A.C., 2007. Permeability and petrophysical properties of 30 natural mudstones. J. Geophys. Res. 112 (B03206), 18.

Younger, P.L., Banwart, S.A., Hedin, R.S., 2002. Mine Water: Hydrology, Pollution, Remediation, vol. 5. Springer.

Yuan, Z., Schubert, J., Esteban, U.C., Chantose, P., Teodoriu, C., 2013. Casing Failure Mechanism and Characterization Under HPHT Conditions in South Texas. SPE 16704.

Zhongxiao, L., Yumin, X., Chuanan, Z., 2000. The Repairing Technology of Driving Channel on Small Drifting-diameter's Casing Damage in Daqing Oilfield. SPE 60599.